HOLLYFRONTIER

February 11, 2013

HAND DELIVERED

Ms. Marian Massoth, Chief
Air Permitting Section
Bureau of Air
Kansas Department of Health and Environment
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366

Re: Source ID No. 0150004
     Construction Permit Application for Naphtha Fractionation Project
     Frontier El Dorado Refining LLC
     El Dorado, Kansas

Dear Ms. Massoth:

Frontier El Dorado Refining LLC (FEDR) hereby submits a Construction Permit Application to the Kansas Department of Health and Environment (KDHE) for the Naphtha Fractionation Project (NFP) to meet the U.S. Environmental Protection Agency (EPA) Mobile Source Air Toxics Phase 2 (MSAT II) final rule dated February 9, 2007. This rule will limit the benzene content of the gasoline produced in the U.S. to a corporate annual average of 0.62 percent by volume. FEDR plans to comply with the MSAT II benzene content requirement by January 1, 2015 as required for small refiners.

The emissions from the NFP will be below the Prevention of Significance Deteriorations (PSD) Significance Levels for all criteria pollutants; however, the Greenhouse Gas (GHG) emissions will be above the PSD threshold; therefore, this project will require a PSD review for GHG.

We are committed to working closely with the KDHE to have the application review completed in a timely manner to meet the projected start of construction in June 2013.

If you have any questions or comments regarding this application, please contact Andrew Beard at (316) 321-8478.

Sincerely,

Theresa Wheeler
Environmental Manager

cc: EPA region 7

Enclosures

FRONTIER EL DORADO REFINING, LLC
2828 N. Harwood St, Suite 1300
Dallas TX   75201-1507

KANSAS DEPT OF HEALTH & ENVIRONMENT
1000 SW JACKSON ST
TOPEKA KS   66612-1367

Check Date		02/01/2013
Check Amount	$	5,500.00
Vendor No		5123082
Payment Document		2000014391
Company Code		1020

Invoice Date	Invoice Number	Description	Invoice Amount	Discount Amount	Net Amount
01/31/2013	PSDPERMIT		5,500.00	0.00	5,500.00

Payment document	Check number	Date	Currency	Payment amount
2000014391	1000208888	02/01/2013	USD	*********5,500.00*

RECEIVED

FEB 1 1 2013

BUREAU OF AIR

! PLEASE FOLD ON PERFORATION AND DETACH HERE !

VERIFY THE AUTHENTICITY OF THIS MULTI-TONE SECURITY DOCUMENT.   CHECK BACKGROUND AREA CHANGES COLOR GRADUALLY FROM TOP TO BOTTOM.

ANTI-FRAUD PROTECTION PATENTS 5,197,765; 5,340,15

FRONTIER EL DORADO REFINING, LLC   64-1278/611   1000208888
2828 N. Harwood St, Suite 1300   02/01/2013
Dallas TX 75201-1507

PAY EXACTLY
*********5,500.00*USD
VOID AFTER 180 DAYS

PAY   *** FIVE THOUSAND FIVE HUNDRED and 00 /100 USD***

TO THE
ORDER OF KANSAS DEPT OF HEALTH & ENVIRO
          1000 SW JACKSON ST
          TOPEKA KS   66612-1367

Stephen D Wise
AUTHORIZED SIGNATURE

Bank of America N.A.

Frontier El Dorado Refining LLC

HOLLYFRONTIER

Construction Permit Application
For
Naphtha Fractionation Project
Source ID No. 0150004

El Dorado, Kansas

February 2013

TABLE OF CONTENTS

TABLE OF CONTENTS - (CONT'D)

TABLE OF CONTENTS - (CONT'D)

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

Appendix A Application Form

Appendix B Documentation of Emission Calculations

Appendix C Tanks 4.09d Outputs

1.1   Purpose of Request

Frontier El Dorado Refining LLC is proposing to modify its Frontier El Dorado Refinery (FEDR) operations to meet the U.S. Environmental Protection Agency (EPA) Mobile Source Air Toxics Phase 2 (MSAT II) final rule dated February 9, 2007. This rule will limit the benzene content of the gasoline produced in the U.S. to a corporate annual average of 0.62 percent by volume. The deadline to meet the MSAT II benzene content requirement is January 1, 2015 for FEDR due to its small refiner status.

New equipment will be installed and existing processes may be altered to facilitate the Naphtha Fractionation Project (NFP) in order to develop the best MSAT II compliance scheme. The NFP will also affect existing downstream equipment but will not require physical modifications.

The emissions from this project will be above certain emission limits specified in Kansas Administrative Regulations (KAR) 28-19-300(a); therefore, a construction permit is required. FEDR is submitting this document to the KDHE for authorization of the proposed NFP to meet the Mandated MSAT II rule.

1.2   Applicant

The applicant is Frontier El Dorado Refining LLC located at 1401 South Douglas Road, in El Dorado, Kansas. Key individuals responsible for preparing this application are as follows:

Technical Contact: Mr. Andrew Beard
                            Environmental Specialist
                            (316) 321-8478

1.3   Project Emission Summary

The FEDR is located in Butler County which is an attainment/non-classifiable county for all criteria pollutants. Therefore, FEDR projects are not subject to non-attainment NSR permitting requirements. However, FEDR is an existing major source as defined within the Prevention of Significant Deterioration (PSD) permit program for all criteria pollutants. Therefore, physical and operational changes at the refinery are potentially subject to PSD permitting requirements.

The proposed NFP will result in a potential increase in emissions for all criteria pollutants. The potential emissions from the calculated emission increases for the NFP compared to the Federal PSD Significance Levels are summarized in Table 1-1 on the following page. A more detailed PSD applicability determination summary is provided in Section 4.

Table 1-1   Project Emissions Increases Compared
to PSD Significance Levels

Source/ Source Category	Potential Emissions (tpy)											
	NO$_x$	SO$_2$	CO	VOC	PM	PM$_{10}$	PM$_{2.5}$	H$_2$SO Mist	H$_2$S	CO$_2$e	NH$_3$	HAPs
New HGU-3 Furnace	36.79	8.98	36.79	4.96	6.85	6.85	6.85	-	-	115,299	-	1.74
HGU-3 Fugitives	-	-	-	0.12	-	-	-	-	-	0.03	-	0.05
Crude Unit Fugitives (increase only)	-	-	-	7.61	-	-	-	-	-	1.90	-	3.04
Naphtha Fract. Tower Fugitives (net increase only)	-	-	-	1.31	-	-	-	-	-	0.33	-	0.52
ISOM Fugitives (increase only)	-	-	-	1.40	-	-	-	-	-	0.35	-	0.56
Gas Con Fugitives (increase only)	-	-	-	1.30	-					0.32		0.52
Cooling Tower (new)	-	-	-	0.06	0.12	0.12	0.12	-	-	0.01	-	-
Gasoline Tanks	-	-	-	0.10	-	-	-	-	-	-	-	-
Isomerate Tanks	-	-	-	2.55	-	-	-	-	-	-	-	-
HGU-3 Atmospheric Vent	-	-	-	0.68	-	-	-	-	-	-	0.35	-
HGU-3 Analyzer Vents	-	-	0.19	0.0004	-	-	-	-	-	-	-	-
Total Project Increases	**36.79**	**8.98**	**36.96**	**20.09**	**6.97**	**6.97**	**6.97**	**0**	**0**	**115,302**	**0.35**	**6.43**
PSD Significance Level	**40**	**40**	**100**	**40**	**25**	**15**	**10**	**7**	**10**	**75,000**	**N/A**	**N/A**
PSD/Netting Required (Y/N)	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**Yes**	**N/A**	**N/A**

1.4 Applicant Organization

The following information is included as part of this application submittal:

- Section 2 summarizes the Process Descriptions and Equipment Changes;
- Section 3 details the Emission Calculation Methodology for the proposed project;
- Section 4 details the PSD Applicability Analysis;
- Section 5 contains the Best Achievable Control Technology (BACT) review;
- Section 6 includes other PSD Requirements;
- Section 7 assesses Regulatory Applicability;
- Appendix A includes Application Forms;
- Appendix B includes the documentation of Emission Calculations; and
- Appendix C contains the TANKS 4.09d Printouts.

SECTION 2
PROCESS DESCRIPTIONS & EQUIPMENT CHANGES

2.1   Overall Refinery Description

The FEDR receives crude oil from a commercial pipeline system and processes the crude oil into an array of marketable products. Crude oil is separated into groups or "fractions" whose molecular structure may be changed or rearranged to form new hydrocarbon compounds with desired characteristics. To produce these compounds, the refinery utilizes processes including distillation, cracking, reforming, isomerization, alkylation, and coking. The refinery processes produce various grades of gasoline, fuel oils, and other fuels, along with petroleum coke, and commercial grade sulfur. The refined products are stored on-site and are transported to markets through a pipeline system, railcars, and commercial trucking operations. A Master Process Flow Diagram is contained as Figure 2-1 of this section.

2.2   Project Specific Descriptions

El Dorado Naphtha Fractionation was studied to develop the best MSAT II compliance strategy among Reformer, Isomerization and Gasoline Blending models based on various fractionation schemes within the refinery. Essentially, the goal of this project is to allow for CRU1 and CRU2 Reformer feed to become nearly benzene and benzene precursor free resulting in the ability to blend gasoline components without benzene extraction. Various changes in method of operation combined with certain physical changes, as outlined below, will facilitate meeting the requirements set forth by the Federal MSAT II requirements.

The equipment and emission summary section contains detailed descriptions of the equipment and associated estimated emissions under the Naphtha Fractionation Project. Emission calculations are included in Appendix B of this application. Brief descriptions of facility changes include both new and revised equipment and/or processes as follows:

- New/Reconstructed:

    a. Replacement of the Crude Unit Stabilizer Column E-315;

    b. Installation of a new 20 MMscfd Hydrogen Plant with 210 MMBTU/hr heater;

    c. Inclusion of miscellaneous fugitive emission components to facilitate piping installation and changes made within process units; and

    d. New Naphtha Fractionation Column.

        The new Naphtha Fractionation Column replaces HTU3 Naphtha Splitter Column (E-1402), the Reformate Splitter Columns and the Deisohexanizer.

- Modified/Change in Method of Operation:
  a. Increase gasoline throughput on various tanks;
  b. Modification of an existing Cooling Tower by revamping an existing cell or adding a new cell; and
  c. Isomerate, currently stored in sphere, will be stored in External Floating Roof (EFR) tanks Tk 227 and Tk 253. Isopentane will be stored in the sphere.

2.3   New Process Equipment

The new technologies to be installed consist of a new Naphtha Fractionation Column, a new Crude Unit Stabilizer, and a new Hydrogen Plant.

2.3.1   Naphtha Fractionation Column

The Naphtha Fractionation Column will take the combined feed from both HTU2 (Heavy Naphtha Hydrotreater) and HTU3 (Light Naphtha Hydrotreater). The Naphtha Fractionation Column will separate these feeds into an iC5 Steam (isopentane rich stream), Isom Feed (predominately C6 hydrocarbons with crude inherent benzene), Intermediate Blend Naphtha (benzene precursors), and Heavy Naphtha reformer feed (benzene and benzene precursor free naphtha). By fractionating in this manner, the benzene that is Light Naphtha will be routed to the ISOM and destroyed; Intermediate Naphtha containing benzene precursors will be blended direct and not routed to the Reformers where they would be converted into benzene; and Heavy Naphtha that is both benzene and benzene precursor free will be used as Reformer Feed. The amount of Naphtha processed through the Reformers will be reduced as well as a reduction in Reformer severity. The resultant Reformate will be nearly Benzene free and can be used directly in gasoline blending.

2.3.2   Crude Stabilizer Column (E-315)

The replacement of the Crude Unit Stabilizer Column E-315 is required as an excess amount of butane is currently routed with Light Naphtha to HTU3. A new Stabilizer column will produce butane free Light Naphtha and reduce the amount of light Naphtha as a substantial amount of butane is removed. The butane will be routed directly the Gas Con Unit for processing. Removing butanes from the Light Naphtha will allow room in the ISOM Unit for benzene destruction. This new Stabilizer Column replaces an existing undersized (for the new service) E-315 column and is considered to be an enclosed system with no source of emissions to the atmosphere.

2.3.3   Hydrogen Plant (HGU-3)

A new Hydrogen Generation Unit (HGU-3) will provide additional high purity hydrogen needed by the refinery as well as additional steam. The new source of Hydrogen is required as the amount of Hydrogen produced by the Reformers will be reduced due to reduction in the amount of naphtha processed and severity reductions at the reformers.

This unit was originally requested for approval of construction December 29, 2010 and approved on May 19, 2011 as part of the Coker Heater and HTU-4 Heater project; however, it was not constructed at that time. This request for approval replaces that construction application for HGU-3. The primary emission source within HGU-3 is the 210 MMBTU/hr (HHV) HGU-3 Reformer Furnace.

Generating hydrogen is done by steam reforming involving the catalytic reaction of natural gas and other refinery gases with similar compositions with steam at temperature ranges of 1400 to 1600 degrees Fahrenheit. This reaction is endothermic and is carried out by passing the gas through catalyst-filled tubes in a furnace. Next, additional steam is used to convert the CO generated in the reforming step to CO_2 and produce additional hydrogen over an oxide-based catalyst. This is an exothermic reaction and is conducted in a fixed-bed catalytic reactor at about 650 degrees Fahrenheit. The third step is removal of CO_2 to produce high purity hydrogen (99.9%) using a "Pressure Swing Adsorption" (PSA) purification unit. The purifier consists of six adsorption vessels with adsorbent. The impurities are adsorbed from the feed gas at the high feed gas pressure and desorbed at a low pressure. The process operates on a repeated cycle having two basic steps, adsorption and regeneration. During normal operation, two vessels are on adsorption and the others are in various stages of regeneration. The regeneration stream (PSA Off-gas) is routed to the HGU-3 furnace as fuel.

HGU-3 produces 600-psig steam which is partially used as process steam and the remainder is let down to the refinery steam system. The amount of steam being let down to the refinery steam system is estimated at 75,000 lb/hr (annual average).

Potential air emissions associated with HGU-3 are from combustion of fuel gas and PSA off-gas in the reformer heater, atmospheric vent (from deaeration and blowdown), and piping fugitives. Maximum firing rate capacity of the reformer heater is 210 MMBTU/hr (annual average), of which, approximately half of the capacity is contributed by combustion of fuel gas, and the rest is made up of PSA off-gas.

2.3.4   Fugitive Emissions Components

The additional fugitive piping components associated with the NFP were estimated to be approximately 20% of the current fugitive component counts for the following units: Crude Unit, NFU and Gas Con. The net increase in fugitive emissions associated with the Naphtha Fractionation Column, the Reformat Splitter and the HTU3 Naphtha Splitter are calculated assuming equal to 20% of HTU3 and 20% of the Reformat Splitter. The fugitive counts of HGU-3 are assumed to be similar to that of HGU-2.

2.4 Modified Process Equipment

Physical changes or changes in the method of operation are planned as part of the execution of the NFP at the El Dorado Refinery.

2.4.1 Cooling Tower

FEDR plans to install an additional cell on an existing cooling tower or revamp an existing cell to support this method of operation required by the MSAT Phase II regulations. The increase in cooling tower circulation rate is estimated to be 300 gallons per minute (gpm).

2.5 Upstream and Downstream Affected Units

The following equipment may be considered affected by the execution of the NFP at the El Dorado Refinery.

2.5.1 Gasoline Storage Tanks – Affected

Gasoline volume will increase due to the changes incorporated as part of this application; therefore, the following tanks may see incremental positive or negative throughputs:

- T17
- T18
- T19
- T20
- T32
- T64
- T65
- T226
- T447

Due to the difficulty in predicting all specific routing, emissions for this project are modeled using Tanks 4.09d and based on worst case emissions potential with an additional 57.5 MMgal modeled through Tank Tk 65 resulting in an increase in VOC emissions of 0.01 tpy (201.51 lbs) annually.

2.5.2 Benzene Tanks – Not Affected

The NFP will essential eliminate benzene waste/by-product from the refinery; therefore, the current benzene storage tanks (Tk 185, Tk 186, Tk 450), the ARU tanks (Tk 4, Tk 448), and the Clay Tower Charge Tank (Tk 449) will likely be re-serviced to light hydrocarbon or sour water; however, the re-service has not been determined. It is expected that there will be no increase in emissions from these tanks.

2.5.3 ISOM and Isopentane Storage - Affected

Isomerate currently stored in a sphere will be stored in EFR tanks Tk 227 and Tk 253. Due to the difficulty in predicting specific routing, isomerate emissions for this project are modeled using Tanks 4.09d and based on worst case emissions potential through Tank Tk 253 resulting in VOC emissions of 2.55 tpy annually.

The sphere will be used to store isopentane. There will be no emissions from the sphere since it operates as a pressure tank.

2.5.4 Loading Facility – Not Affected

The anticipated increase in gasoline production associated with the NFP will be transported from the El Dorado Refinery via pipeline; therefore, no increase in loading emissions from transport vessels is expected. Thus, gasoline loading facility is not considered downstream affected equipment.

The NFP will result in nearly benzene free or benzene precursor free to the CRUs; therefore, no benzene extraction is required before gasoline blending. Thus, benzene loading will be eliminated, and the benzene loading rack may be down or will be used for loading other products. No increase in loading emissions at the benzene loading rack is expected.

2.5.5 Steam Usage – Not Affected

Any increase in steam consumption associated with the NFP will be off-set by the steam production from the new HGU-3. Therefore, no increase in existing boiler firing rates associated with the NFP is expected.

2.5.6 Wastewater – Affected

There will be new wastewater streams generated from the NFP project. Potential new Benzene Waste Organic NESHAP (BWON) streams will be controlled. However, no increase in crude processing associated with the NFP project; therefore, no increase in overall wastewater is expected.

PROCESS OFF GASES
NATURAL GAS
NATURAL GASOLINE

FUEL GAS

GLU LPGT

ACID GAS

SULFUR UNITS

SULFUR

HGU-1 HGU-2 HGU-3

TO H2 USERS

C4 TO GASCON

CRUDE STABI-LIZER

LT SR GASOLINE

HEAVY SR GASOLINE

HTU-3

HTU-2

GASCON

ISOM

ISOMERATE TO GASOLINE BLENDING

IC5

INTERMEDIATE NAPHTHA

NAPHTHA FRACTIONATION

TO GASCON

CRU 1

CRU 2

TO GASCON

HEAVY REFORMATE TO GASOLINE BLENDING

HSR TO GASOLINE BLENDING

HTU1

KEROSENE / JET FUEL

LCO

TO GASOLINE

ALKY UNITS

ISOBUTANE

STEAM / POWER

FCCU VRU

HTU5

ULS DISTILLATE

HS DISTILLATE

HTU4

ULS DISTILLATE

GOFINER

ACID GAS

ACID GAS

LC GO

HRSG

COMBUSTION TURBINE

NATURAL GAS

DISTILLATE

GAS OIL

COKER

COKE

CRUDE UNIT

CRUDE

VACUUM UNIT

ASPHALT

FIGURE 2-1 MASTER PROCESS FLOW DIAGRAM
NAPHTHA FRACTIONATION PROJECT

NEW UNITS

MODIFIED UNITS

Figure 2-2 HGU-3 Block Flow Diagram

- Water
- SMR Combustion Stack
- Natural Gas for H₂ Production
- Sulfur Guard
- SMR Steam Methane Reformer/Boiler
- Steam Supply to SMR Process-Side
- 75,000 lb/hr steam
- Deaeration/blow down
- Shift Reactor
- Pressure Swing Adsorbers (PSAs)
- 20 MMscfd H₂
- PSA Tail Gas Fuel to SMR Combustion-Side
- Combustion Air
- Refinery Fuel Gas to SMR Combustion-Side
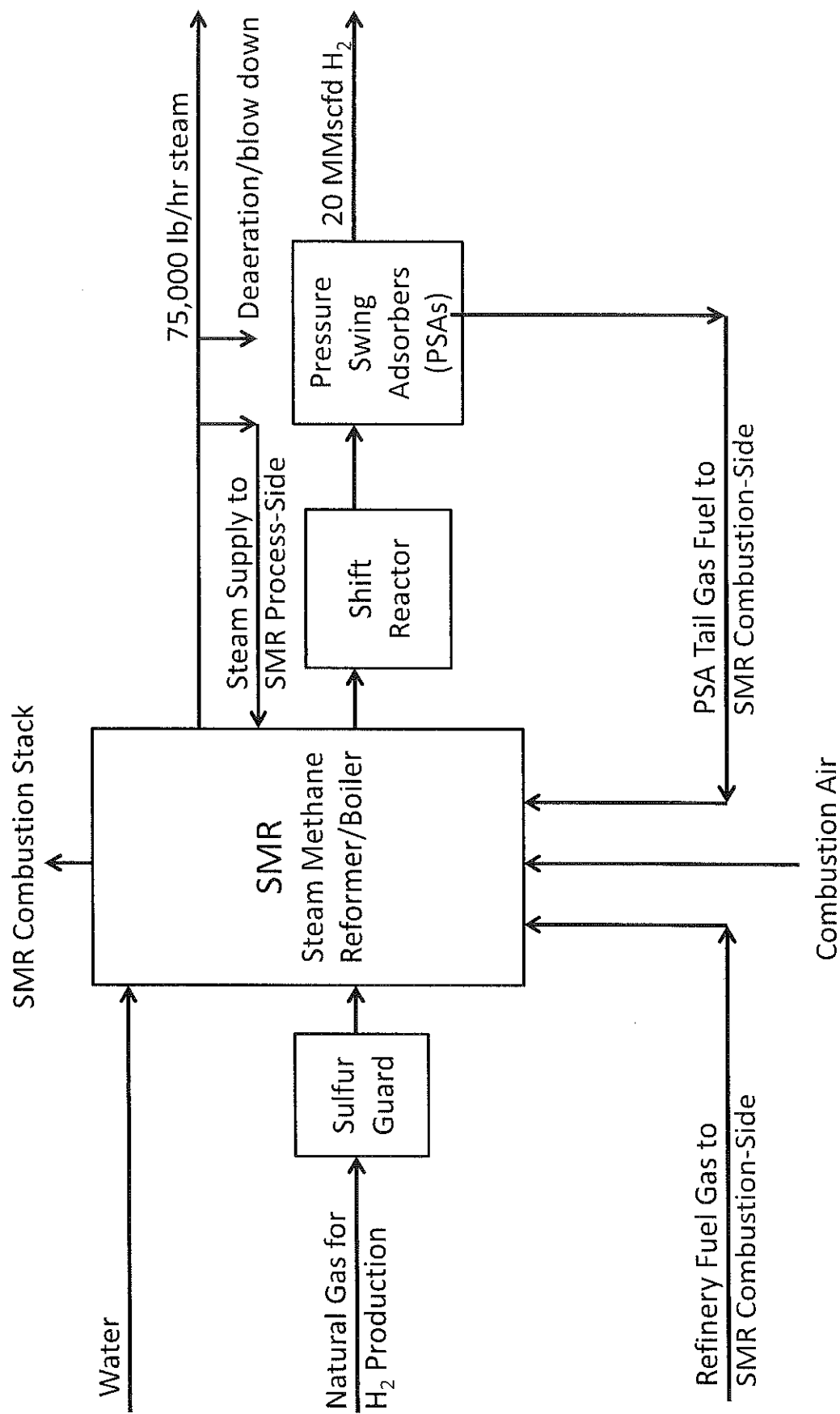
SECTION 3
EMISSION CALCULATION METHODOLOGY

This section describes the air emissions associated with this application. The emissions calculated for this application include the NO_x, SO_2, CO, VOC, $PM/PM_{10}/PM_{2.5}$ and HAPs emissions from new sources as well as modified existing sources as applicable. GHG PSD permitting applies to new and modified sources after February 2011. The NFP includes new GHG emission sources; therefore, GHG emission calculations are included as part of this application.

3.1   HGU-3 Furnace

The emission calculations for the new HGU-3 furnace are described in the following subsections. There are no modifications to any existing combustion devices associated with the NFP.

All potential annual emission rates were calculated based on 8,760 hours per year.

3.1.1   NOx Emissions

Short-term (lb/hr) NO_x emissions from the HGU-3 furnace were estimated using a NOx emission factor of 0.06 lb NO_x/MMBtu which is 15% above the 0.04 lb/MMBtu 30-day rolling average limit from NSPS Ja, and the design maximum heat input. Annual (tpy) NO_x emissions from the HGU-3 furnace were estimated using a NOx emission factor of 0.04 lb NO_x/MMBtu based on the NO_x limit set by NSPS Ja and the design maximum heat input.

3.1.2   SO₂ Emissions

Short-term (lb/hr) and annual (tpy) emissions of SO_2 from the HGU-3 furnace were estimated using NSPS Ja's 3-hour rolling limit of 162 ppmv and 365-day rolling limit of 60 ppmv H_2S, and the design maximum heat input of the furnace. The compliance limit concentrations were converted to lb SO_2/MMBtu using ideal gas law volume and a typical higher heating value (HHV) for natural gas.

3.1.3   CO Emissions

Short-term (lb/hr) and annual (tpy) emissions of CO from the HGU-3 furnace were estimated based on a vendor guarantee of 0.04 lb CO/MMBtu, and the design maximum heat input value.

3.1.4 VOC and $PM/PM_{10}/PM_{2.5}$ Emissions

Short-term (lb/hr) and annual (tpy) emissions of VOC and $PM/PM_{10}/PM_{2.5}$ from the HGU-3 furnace were estimated based on the lb/MMscf factors found in Table 1.4-2 of AP-42's *Chapter 1: External Combustion Devices*, 5th edition, and the design heat input value. The AP-42 factors were converted from lb/MMscf to lb/MMBtu by diving by 1020 per Note "a" of Table 1.4-2. Per Note "c" of Table 1.4-2, all PM is assumed to be less than 1.0 micrometer in diameter and therefore the emission factors can be used to estimate PM_{10} and $PM_{2.5}$.

3.1.5 Hazardous Air Pollutant (HAP) Emissions

Annual (tpy) emissions of HAPs from the HGU-3 furnace were estimated based on the lb/MMscf factors found in Tables 1.4-3 and 1.4-4 of AP-42's *Chapter 1: External Combustion Devices*, 5th edition, and the design heat input value. The AP-42 factor was converted from lb/MMscf to lb/MMBtu by diving by 1020 per Notes "a" of Tables 1.4-3 and 1.4-4.

3.1.6 Greenhouse Gas (GHG) Emissions

Potential CO_2e emissions were calculated using Tier 3 calculation methodology in 40 CFR Part 98, Subpart C. This method uses equations C-5 for CO_2 and C-8 for CH_4 and N_2O of 40 CFR Part 98 with design heat input, Global Warming Factors of 21 for CH_4 and 310 for N_2O from 40 CFR Part 98 Subpart A, Table A-1.

3.2 Fugitives

3.2.1 VOC Emissions

Potential fugitive emissions associated with the NFP will be from an estimated 20% additional fugitive components from the Crude Unit, the ISOM and the Gas Con unit. The net increase in fugitive emissions associated with the Naphtha Fractionation Column, the Reformat Splitter and the HTU3 Naphtha Splitter are calculated assuming equal to 20% of HTU3 components and 20% of the Reformat Splitter components. The potential fugitive emissions associated with the HGU-3 are calculated based on estimated number of components for the new Hydrogen Unit HGU-3.

These fugitive emissions have been estimated based on EPA guidance[1]. SOCMI emission factors for a leak definition of <10,000 ppmv found in Table 2-5 of the report were used to estimate the fugitive emissions to provide consistency with the Emission Inventory calculations published by the site. The use of SOCMI emission factors is allowed by the EPA's Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA). Detailed calculations are provided in Appendix B of this report.

---

[1] U.S. Environmental Protection Agency/Office of Air Quality, Planning and Standards: Protocols for Equipment Leaks Emission Estimate; EPA-453/R-95-017, November 1995.

3.2.2 Hazardous Air Pollutant (HAP) Emissions

Organic HAP emissions were calculated for fugitive emissions based on a conservative assumption of 40% emissions from equipment leaks.

3.2.3 Greenhouse Gas (GHG) Emissions

Emissions of CO_2e were conservatively estimated from the highest conceivable CH_4 content (25%) of VOC in the process streams.

3.3 Cooling Tower

3.3.1 VOC and PM/PM10/PM2.5 Emissions

Increases in hourly and annual PM emissions from the cooling tower have been estimated based on the methodology presented in AP-42, Chapter 13.4 (1/95), a site-specific Total Dissolved Solids (TDS) content of 910 ppmv and a projected increased circulation rate of 300 gpm. Due to a small estimated amount of PM/PM_{10} emissions, it is conservatively assumed that all PM/PM_{10} are equal to $PM_{2.5}$. Increase in VOC emissions has also been estimated from the cooling tower using the emission factor of 0.7 pounds per million gallons circulated as presented in Table 5.1-2 of AP-42, Section 5.1 (1/95).

3.3.2 Hazardous Air Pollutants (HAP) Emissions

Due to the low mass emissions conservatively calculated for VOC and the low expected HAP content, the HAP emissions from cooling tower leaks are expected to be insignificant.

3.3.3 Greenhouse Gas (GHG) Emissions

Emissions of CO_2e were conservatively estimated from the highest conceivable CH_4 content (25%) of VOC in cooling water.

3.4 Tanks

3.4.1 VOC Emissions

Annual VOC emissions from gasoline tanks from the project were estimated based on an assumed increase of 3,750 bpd of gasoline. The increase in throughput was applied to all gasoline tanks and the worst-case emissions (from tank Tk 65) were selected.

Annual VOC emissions from isomerate tanks from the project were estimated based on an assumption that all isomerate could be stored in either isomerate tank. The worst-case emissions (from tank Tk 253) were selected.

3.4.2 Hazardous Air Pollutants (HAP) Emissions

Due to the low mass emissions conservatively calculated for VOC, the HAP emissions are from tanks are expected to be insignificant.

3.4.3 Greenhouse Gas (GHG) Emissions

CH_4 is not expected to be present in the gasoline product stream that may experience an increase by 3,750 bpd, and GHG is therefore not calculated for this source.

Emission increases associated with applicable equipment and increased emissions from affected equipment for the NFP are below the PSD significance levels, except for GHG. Since the project emission increase of GHG is above the PSD significance levels for GHG, and no contemporaneous decreases in GHG emissions, a PSD review will be required for GHG emissions associated with the Project.

4.1.1 NSR Source Classification

The facility is an existing major source as defined by the New Source Review (NSR) permitting program.

4.1.2 Federal NSR Applicability for Non-Greenhouse Gas (GHG) Pollutants

The Frontier El Dorado Refinery is located in Butler County which is an attainment/non-classifiable county for all criteria pollutants. Therefore, nonattainment regulations do not apply. The project emission increases for all criteria pollutants are below the respective PSD Significance Levels. Therefore, PSD review is not required for these criteria pollutants. The project emissions for non-GHG pollutants are summarized in Table 4-1 below.

Table 4-1   Project Non-GHG Pollutant Applicability Analysis

POLLUTANT	PROJECT INCREASES	PSD SIGNIFICANCE LEVEL	NETTING CALCULATIONS REQUIRED	CONTEM-PORANEOUS INCREASES/ DECREASES	PSD NET EMISSIONS INCREASES	PSD REVIEW REQUIRED
	(Ton/yr)	(Ton/yr)	(Yes/No)	(Ton/yr)	(Ton/yr)	(Yes/No)
NO_x	36.79	40	No	-	36.79	No
SO_2	8.98	40	No	-	8.98	No
CO	36.98	100	No	-	36.98	No
VOC	20.09	40	No	-	20.09	No
PM	6.97	25	No	-	6.97	No
PM_{10}	6.97	15	No	-	6.97	No
$PM_{2.5}$	6.97	10	No	-	6.97	No
NH_3	0.35	Not Applicable	-	-	0.35	No
HAPs	6.43	Not Applicable	-	-	6.43	No

It should be noted that lead and fluorides are not included in the PSD analysis because they are not emitted from the affected sources of this project.

4.1.3   Federal NSR Applicability for GHG

PSD applies to the GHG emissions from a proposed NFP if any of the following is true:

- The existing source's potential-to-emit (PTE) for GHGs is equal to or greater than 100,000 TPY on a CO_2 equivalent (CO_2e) basis and is equal to or greater than 100/250 TPY (depending on the source category) on a mass basis, and

- The emissions increase and the net emissions increase of GHGs from the modification would be equal to or greater than 75,000 TPY on a CO_2e basis and greater than zero TPY on a mass basis.

The Frontier El Dorado Refinery is an existing major source for all criteria pollutants and has a PTE for GHGs greater than 100,000 TPY on a CO_2e basis and greater than 100 TPY on a mass basis. GHG emissions from the proposed NFP including Carbon Dioxide (CO_2), Methane (CH_4), and Nitrous Oxide (N_2O). Note that no other emissions of GHG regulated pollutants (hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) nor sulfur hexafluoride (SF_6)) are emitted as part of the project. As shown on Table 4-2 below, the project increase in GHG emissions expressed as CO_2e is greater than 75,000 TPY; therefore, the project triggers a PSD review for GHG emissions.

Table 4-2   Project GHG Emission Summary

POLLUTANT*	PROJECT GHG NET EMISSION INCREASES TPY
CO_2, CH_4, N_2O expressed as CO_2e	115,302.37

This table shows that the proposed NFP triggers PSD review for CO_2e. For each pollutant that triggers PSD review, it is required by Kansas Regulations (KAR 28-19-350, references 40 CFR §51.21) that Best Available Control Technology (BACT) be applied to all emission units which, as a result of the project, are new or have undergone a physical or operational change.   Because there are no ambient air standards associated with CO_2e emissions, FEDR believes that it is not necessary to perform an air quality demonstration for CO_2e.

5.1 Overview of Top-Down BACT

KAR 28-19-350, which refers to 40 CFR 52.21, requires that new and modified sources apply best available control technology (BACT) to control emissions for each regulated pollutant emitted from a major modification of an existing major stationary source located in an attainment area for that pollutant. The EPA endorses the Top-Down approach to BACT analysis. Under this approach, BACT is defined as the best control technology that is currently available as determined on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs of alternative control systems.

The five basic steps of Top-down procedure are:

Step 1 - Identify available control technologies;

Step 2 - Eliminate technically infeasible options;

Step 3 - Ranking Remaining Control Options Based on Effectiveness;

Step 4 - Evaluate Most Cost Effective Controls; and

Step 5 - Selection of BACT.

Step 1 - Identify All Available Control Technologies

The first step is to identify all "available" control options for each new or modified piece of equipment which triggers PSD for each pollutant under review. Available control options are those technologies or techniques with a practical potential for application to the equipment. During the course of the BACT analysis, one or more control options may be eliminated from consideration. However, at the outset, a comprehensive list must be compiled. This list should include potentially applicable Lowest Achievable Emission Rate (LAER) technologies, innovative technologies, and controls applied to similar source categories.

Step 2 – Eliminate Technically Infeasible Technologies

The second step of the top-down analysis is to arrange the comprehensive list, created in Step 1, based on technical feasibility. The technical evaluation should clearly document the difficulties based on source-specific factors and physical, chemical, and engineering principles that preclude the safe and successful use of the control option. Technically infeasible control technologies are removed from further evaluation.

Step 3 – Rank Remaining Control Options by Control Effectiveness

In the third step, all remaining control technologies are ranked by overall control effectiveness. Each control option and its control efficiency, expected emission rate, expected emission reduction, economic impacts, environmental impacts, and energy impacts is presented in this step.

Step 4 – Evaluate Most Effective Controls and Document Results

Based on the rank order developed in Step 3, the most effective control is evaluated based on its energy, environmental, and economic impacts. If the top control is eliminated as BACT, the next control option is selected and similarly evaluated. "This process continues until the technology under consideration cannot be eliminated by any source specific energy, environmental, or economic impacts which demonstrate that alternative to be inappropriate as BACT."

Step 5 – Select BACT

In this step, the most effective control not rejected in Step 4 is selected as BACT. If all control options are rejected as BACT, then no add-on control is considered BACT.

5.2   Detailed Top-Down BACT Analysis

5.2.1   BACT for HGU-3 Furnace – GHG BACT

This project includes the construction of a new furnace for the proposed hydrogen generation unit. The project increases trigger PSD for CO and CO_2e. The following sub-sections present a review of BACT for this combustion unit for CO and CO_2e emissions.

The new HGU-3 refomer furnace will be fired with refinery fuel gas and/or PSA purge gas. The combustion units will emit three GHGs: CH_4, CO_2, and N_2O. CO_2 will be emitted from these sources because it is a combustion product of any carbon-containing fuel. CH_4 will be emitted from these sources as a result of any incomplete combustion of refinery fuel gas. N_2O will be emitted from these sources in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process.

All fossil fuels contain significant amounts of carbon but the refinery fuel gas that will be combusted in the furnace is a low carbon fuel. One of the useful byproducts produced by the petroleum refining process is refinery fuel gas. This gas is generally similar to natural gas but contains less methane and more hydrogen and ethane than natural gas does. In the combustion of a fossil fuel, the fuel carbon is oxidized into CO and CO_2. Full oxidation of fuel carbon to CO_2 is desirable because CO has long been a regulated pollutant with established adverse environmental impacts, and because full combustion releases more useful energy within the process. In addition, emitted CO gradually oxidizes to CO_2 in the atmosphere.

The first step of the BACT analysis is to identify all available control technologies. The RBLC is a useful resource to identify any approved BACT determinations. Based on a December 2012 database query of permits issued after 2002 in the RBLC, there was one GHG BACT determination related to petroleum refineries, and it was for a steam methane reformer furnace similar to the HGU proposed in this project. There are three other RBLC GHG BACT determinations for power plants (RBLC IDs: VT-0037, IA-0101) and a fertilizer manufacturer (RBLC ID: IA-105). Good combustion practices and energy efficiency are BACT as identified by these entries.

Given that there is relatively little case-specific GHG information due to the recent start of the GHG program, other published EPA GHG BACT guidance will be referenced. EPA has released the following documents that were used to identify potential control technologies and work practices:

- Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries: An ENERGY STAR Guide for Energy Plant Managers. Document Number LBNL-56183, February 2005;

- Available and Emerging Technologies for Reducing Green House Gas (GHG) emissions from the Petroleum Refining Industry, EPA, October 2010;

- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers, EPA, October 2010; and

- EPA's GHG Mitigation Database was accessed several times during the permit application update in October 2012. However, the system was inoperable during that time with a message "The requested resource (/GHGMDB/) is not available."

A BACT analysis for CO_2 emissions is presented in the following steps.

5.2.1.1 Step 1 – Identification of CO_2 Control Technologies

The following technologies were identified as CO_2 control options for the new combustion unit based on available information and data sources:

- Use of Low Carbon Fuels;
- Use of Good Combustion Practices;
- Energy Efficient Design;
- Pre-Combustion Carbon Capture and Storage (CCS); and
- Post-Combustion CCS.

5.2.1.1.1 Low Carbon Fuels

Table 5-1 in this section presents the amount of CO_2 formed when combusting fossil fuels, including some of the fuels that will be used by the new combustion unit.

Table 5-1 CO_2 Emission Factors[1]

Fuel Type	Default CO_2 Emission Factor
Coal and coke	kg CO_2/mmBtu
Anthracite	103.54
Bituminous	93.40
Subbituminous	97.02
Lignite	96.36
Coke	102.04
Natural gas	kg CO_2/mmBtu
(Weighted U.S. Average)	53.02
Distillate Fuel Oil No. 1	73.25
Distillate Fuel Oil No. 2	73.96
Distillate Fuel Oil No. 4	75.04
Residual Fuel Oil No. 5	72.93
Residual Fuel Oil No. 6	75.10
Used Oil	74.00
Kerosene	75.20
Liquefied petroleum gases (LPG)	62.98
Propane	61.46
Propylene	65.95
Ethane	62.64
Ethanol	68.44
Ethylene	67.43
Isobutane	64.91
Isobutylene	67.74
Butane	65.15
Butylene	67.73
Natural Gasoline	66.83
Other Oil (>401 deg F)	76.22
Pentanes Plus	70.02
Petrochemical Feedstocks	70.97
Petroleum Coke	102.41

Fuel Type	Default CO_2 Emission Factor
Special Naphtha	72.34
Unfinished Oils	74.49
Heavy Gas Oils	74.92
Lubricants	74.27
Motor Gasoline	70.22
Aviation Gasoline	69.25
Kerosene-Type Jet Fuel	72.22
Asphalt and Road Oil	75.36
Other fuels-solid	kg CO_2/mmBtu
Municipal Solid Waste	90.7
Tires	85.97
Plastics	75.00
Petroleum Coke	102.41
Other fuels—gaseous	kg CO_2/mmBtu
Blast Furnace Gas	274.32
Coke Oven Gas	46.85
Propane Gas	61.46
Fuel Gas	**59.00**

Fuel Type	Default CO_2 Emission Factor
Biomass fuels—solid	kg CO_2/mmBtu
Wood and Wood Residuals	93.80
Agricultural Byproducts	118.17
Peat	111.84
Solid Byproducts	105.51
Biomass fuels—gaseous	kg CO_2/mmBtu
Biogas (Captured methane)	52.07
Biomass Fuels—Liquid	kg CO_2/mmBtu
Ethanol	68.44
Biodiesel	73.84
Biodiesel (100%)	73.84
Rendered Animal Fat	71.06
Vegetable Oil	81.55

[1] *Obtained from 40CFR98, Subpart C, Table C-1*

As shown in the table above, the use of natural gas and refinery fuel gas reduces the production of CO_2 from combustion of fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels (i.e., distillate or residual oils).

5.2.1.1.2 Good Combustion Practices

Good combustion practices for process heaters fired with refinery fuel gas include the following:

- Good air/fuel mixing in the combustion zone;

- Sufficient residence time to complete combustion;

- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;

- Good burner maintenance and operation;

- High temperatures and low oxygen levels in the primary combustion zone;

- Monitor oxygen levels and air intake to optimize the fuel/air ratio and minimize excess air;

- Implementing a maintenance program to monitor fouling conditions in the subject combustion units; and

- Conduct a thermal tune-up annually. The tune-up will consist of inspection of the burner, flame pattern, and air-to-fuel ratio.

5.2.1.1.3 Energy Efficient Design

When possible, the use of the following can provide an energy efficient design to minimize the required fuel combustion for process heaters.

- Combustion Air Preheat;
- Process Integration and Heat Recovery;
- Use newer burner with latest proven engineering design; and
- Excess Combustion Air Monitoring and Control.

5.2.1.1.4 Pre-Combustion or Post-Combustion Carbon Capture and Storage (CCS)

As referenced in the March 2010 GHG Title V and PSD permitting guidance (Document No. EPA457/B11-001), EPA has identified CCS as an available add-on control technology that must be evaluated as if it were technically feasible.

Pre-combustion carbon capture for fuel gas combustion involves substituting pure oxygen for air in the combustion process, resulting in a concentrated CO2 exhaust stream so it may be captured more effectively. The oxygen may be isolated from air using a number of technologies, including cryogenic separation and membrane separation. Post-combustion carbon capture for fuel gas combustion is applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO2 from the combustion exhaust gases. There are a number of methods and processes that could be used to capture CO2 from the dilute exhaust gases produced by the new combustion units. These capture technologies include separation with solvent or physical filters, cryogenic separation to condense the CO2, and membrane separation technologies. In addition, the CCS technology is also comprised of the distinct stages below:

- Pressurization of the captured CO_2;
- Transmission of CO_2 via pipeline; and
- Injection and long term storage of the captured CO_2.

In order to provide effective reduction of CO_2 emissions, efficient methods of compression, transport, and storage would also be required. This would require transporting the captured CO_2 to a suitable geological storage formation including the following:

- Depleted oil and gas reservoirs;
- Unmineable coal seams;
- Saline formations;

- Basalt formations; and
- Terrestrial ecosystems.

There are several major unresolved issues with respect to CO_2 sequestration including the legal process for closing and remediating sequestration sites and liability for accidental releases from these sites.

5.2.1.2 Step 1 - CH_4 and N_2O Control Technologies

The following technologies were identified as CH_4 and N_2O control options for the new combustion units based on available information and data sources.

- Use of low carbon fuels;
- Use of good combustion practices;
- Energy efficient design; and
- Oxidation catalysts (CH4 Control Only).

5.2.1.2.1 Low Carbon Fuels

The following table presents the default emission factors of CH_4 and/or N_2O formed when combusting fossil fuels, including some of the fuels that will be used by the new combustion units.

Table 5-2 CH_4 and N_2O Emission Factors[2]

Fuel type	Default N_2O emission factor (kg CH_4/mmBtu)	Default CH_4 emission factor (kg CH_4/mmBtu)
Coal and Coke (All fuel types in Table C–1)	1.6×10^{-03}	1.1×10^{-02}
Natural Gas	1.0×10^{-04}	1.0×10^{-03}
Petroleum (All fuel types in Table C–1)	6.0×10^{-04}	3.0×10^{-03}
Municipal Solid Waste	4.2×10^{-03}	3.2×10^{-02}
Tires	4.2×10^{-03}	3.2×10^{-02}
Blast Furnace Gas	1.0×10^{-04}	2.2×10^{-05}
Coke Oven Gas	1.0×10^{-04}	4.8×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C–1)	4.2×10^{-03}	3.2×10^{-02}
Biogas	6.3×10^{-04}	3.2×10^{-03}
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1×10^{-04}	1.1×10^{-03}

[2] Obtained from 40CFR98, Subpart C, Table C-2.

As shown in the table, the use of natural gas and refinery fuel gas reduces the production of CH_4 and N_2O from combustion of fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels (i.e., distillate or residual oils).

5.2.1.2.2 Good Combustion Practices

Good combustion practices for the new combustion units fired with refinery fuel gas include the following:

- Good air/fuel mixing in the combustion zone;

- Sufficient residence time to complete combustion;

- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;

- Good burner maintenance and operation;

- High temperatures and low oxygen levels in the primary combustion zone;

- Monitor oxygen levels and air intake to optimize the fuel/air ratio and minimize excess air;

- Implementing a maintenance program to monitor fouling conditions in the subject combustion unit; and

- Conduct a thermal tune-up annually. The tune-up will consist of inspection of the burner, flame pattern, and air-to-fuel ratio.

5.2.1.2.3 Energy Efficient Design

When possible, the use of the following can provide an energy efficient design for the new combustion units minimizing the required fuel combustion for process heat.

- Combustion Air Preheat;

- Process Integration and Heat Recovery;

- Use newer burner with latest proven engineering design; and

- Excess Combustion Air Monitoring and Control.

5.2.1.2.4 Oxidation Catalysts

Oxidation catalyst has been widely applied as a control technology for CO and VOC emissions from natural gas-fired combined cycle gas turbines and would also provide reduction in CH_4 emissions. This technology utilizes excess air present in the combustion exhaust and the activation energy required for the reaction to lower CH_4 concentration in the presence of a catalyst. The optimum temperature range for these systems is approximately 850°F to 1,100°F. No chemical reagent addition is required.

5.2.1.3 *Step 2 – Eliminate Technically Infeasible Options*

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

5.2.1.3.1 Carbon Capture and Storage – Technically Infeasible

The pre-combustion technique for CO_2 separation involves substituting pure oxygen for air in the combustion process, resulting in a concentrated CO_2 exhaust stream. This "oxyfuel" process has not yet been tested or demonstrated in a project such as the new combustion units at the refinery. However, for purposes of BACT analysis, it is assumed that this technology would be technically feasible since it is both available and applicable.

There are a number of methods and processes that could be used to capture CO_2 from the dilute exhaust gases produced by the new combustion units. These capture technologies include separation with solvent or physical filters, cryogenic separation to condense the CO_2, and membrane separation technologies.

5.2.1.3.1.1 Separation with Solvent Scrubbers – Technically Infeasible

There are many solvents under development for the separation of CO_2 from combustion of flue gases through chemical absorption. The most commercially developed of these processes use monoethanolamine (MEA) as the solvent. MEA has the advantage of fast reaction with CO_2 at low partial pressure. The primary concern with MEA is corrosion in the presence of O_2 and other impurities, high solvent degradation rates due to reactions with SO_2 and NO_X, and the energy requirements for solvent regeneration.

Diethanolamine (DEA) is another solvent available for CO_2 removal. While some research shows that slightly lower CO_2 overheads can be achieved with DEA relative to MEA, the same problems with corrosion and high degradation rates exist, in addition to foaming tendencies. Another commercially available solvent is methyldiethanolamine (MDEA), which offers advantages over MEA and DEA, such as low corrosion, slow degradation rates, low amine reboiler duty, reduced solvent losses, and low circulation demand. However, its slow reaction rate for CO_2 makes it impractical when removal of large amounts of CO_2 is desired, such as with the new combustion units in this application. Therefore, FEDR does not believe using solvent scrubbing with MEA, DEA or MDEA is a technically feasible technology for this application.

Solvent scrubbing has been used in the chemical industry for separation of CO_2 in exhaust streams and is a technically feasible technology for this application; however, it has not been demonstrated in large scale industrial process applications.

5.2.1.3.1.2 Cryogenic Separation – Technically Infeasible

The cryogenic CO_2 capture process includes the following steps:

- Dry and cool the combustion flue gas;
- Compress the flue gas;
- Further cool the compressed flue gas by expansion which precipitates the CO_2 as a solid;
- Pressurize the CO_2 to a liquid; and
- Reheat the CO_2 and remaining flue gas by cooling the incoming flue gases.

The final result is the CO_2 in a liquid phase and a gaseous nitrogen stream that can be vented through a gas turbine for power generation. The CO_2 capture efficiency depends primarily on the pressure and temperature at the end of the expansion process. However, this process has not been commercially demonstrated on gas streams with low CO_2 concentrations such as the new combustion units at the petroleum refinery. To date there is insufficient data available to accurately complete cost analyses for this developmental technology.

5.2.1.3.1.3 Membrane Separation – Technically Infeasible

This method is commonly used for CO_2 removal from natural gas at high pressure and high CO_2 concentration. Membrane-based capture uses permeable or semi-permeable materials that allow for selective transport/separation of CO_2 from flue gas. It has been estimated that 80 percent of the CO_2 could be captured using this technology. The captured CO_2 would then be purified and compressed for transport. Membrane technology is not fully developed for CO_2 concentration and gas flow to boilers and process heaters at a petroleum refinery. To date there is insufficient data available to accurately complete cost analyses for this developmental technology.

5.2.1.3.1.4 Carbon Transport and Storage Separation – Technically Infeasible

There are available technically feasible methods for compression, transport, and storage of concentrated CO_2 streams. Options for capturing emissions from the new combustion units fired with refinery fuel gas, which would be required as an element of CCS as a GHG emission control option, were discussed in the preceding three subsections under carbon capture and storage.

5.2.1.3.1.5 Oxidation Catalysts – Technically Infeasible

Oxidation catalysts are not technically feasible. The typical oxidation catalyst for CH_4-containing exhaust gases is rhodium or platinum (noble metal) catalyst on an alumina support material. This catalyst is installed in an enlarged duct or reactor with flue gas inlet and outlet distribution plates. Acceptable catalyst operating temperatures range from 400 to 1250 °F, with the optimal range being 850 to 1,100 °F. Below approximately 600 °F, a greater catalyst volume would be required to achieve the same reductions. To achieve this temperature range in boilers or process heaters fired with refinery fuel gas, the catalyst would need to be installed in the heater upstream of any waste heat recovery or air preheat equipment.

Installation of oxidation catalyst in flue gas containing more than trace levels of SO_2 will result in poisoning and deactivation of the catalyst by sulfur-containing compounds, as well as increasing the conversion for SO_2 to SO_3. The increased conversion of SO_2 to SO_3 will increase condensable particulate matter emissions and increase flue gas system corrosion rates. For these reasons, catalytic oxidation of CH_4 is not considered technically feasible for the refinery fuel gas fired boiler.

5.2.1.3.1.6 Lower Carbon Fuels – Technically Infeasible

The new combustion units will combust refinery fuel gas and PSA off-gas which are low-carbon fuels. The only identified fuels with lower CO_2 formation rates are syngas, pressure swing adsorption ("PSA") tail gas, and natural gas. Production of additional syngas or PSA tail gas would lead to overall increases in GHG emissions from the refinery and do not represent options for reducing GHG emission. Natural gas is commercially available and would yield slightly reduced CO_2 emission rates from the new combustion units, but displacing refinery fuel gas from use as fuel in the new combustion units would necessitate disposal of this fuel gas by combustion elsewhere at the refinery, such as by flaring, which would increase overall CO_2 emissions from the site. Thus there are no control options involving the use of lower carbon fuels in the new combustion unit that is technically feasible for reducing GHG emissions relative to the proposed use of refinery fuel gas, and available PSA purge gas.

5.2.1.3.1.7 Good Combustion Practices – Technically Feasible

Good combustion practices for boilers and process heaters fired with refinery fuel gas are technically feasible and are inherent in the design of the new combustion units.

5.2.1.4 *Step 3 – Rank Remaining Control Technologies*

The following technologies and control efficiencies were identified as technically feasible for CO_2 control options for boilers and process heaters based on available information and data sources:

- Post-Combustion CCS (assumed 93% control efficiency);
- Pre-Combustion CCS (assumed 87% control efficiency);
- Use of low carbon fuels (control efficiency is not applicable);
- Use of good combustion practices (efficiency is not applicable); and
- Energy efficient design (efficiency is not applicable).

5.2.1.5 *Step 4 – Evaluate the Most Effective Controls and Document Results*

5.2.1.5.1 *Use of Low Carbon Fuels, Good Combustion Practices and Energy Efficient Design*

The use of low carbon fuels and good combustion practices are inherent in the design and operation of the new combustion units associated with this project. Good combustion practices are identified as GHG BACT for other issued PSD projects (RBLC IDs: IA-0105, IA-0101).

Continuously monitored indicators will be used to ensure that the new combustion units will operate within optimum design parameters. These parameters include: fuel flow and stack O_2 and temperature. Annual tune-ups for thermal efficiency as a work practice standard will be conducted. Other energy efficient designs will be incorporated as feasible, depending on the boiler's configuration; specifically, the use of Combustion Air Preheat, Process Heat to Generate Steam, Process Integration and Heat Recovery, and Excess Combustion Air Monitoring and Control. Energy efficiency is identified as GHG BACT for other issued PSD projects (RBLC IDs: VT-0037).

In addition, the new combustion units will be operated according to the manufacturer's specifications and monitoring will be consistent with the site's GHG monitoring plan required by 40 CFR Part 98.

5.2.1.5.2 *Carbon Capture Systems*

5.2.1.5.2.1 *Post-Combustion Carbon Capture*

For the purposes of the following analysis of CCS, chemical absorption using MEA based solvents is assumed to represent the best post-combustion CO_2 capture option. This capture efficiency is assumed to be 93 percent effective. The CO_2 emissions from the new combustion units are estimated to be 115,304 tons per year. The CO_2

rich solvent from the scrubber would then be pumped to a regeneration system for CO_2 removal and reuse. The CO_2 would need to be dried, compressed from low pressure up to 2,000 psi and transported by pipeline to the nearest pipeline that would conceivably use the supply for Anadarko pipeline approximately 90 miles away. This scenario provides a lower cost estimate than assuming direct transportation to the nearest storage reservoir, the Teapot Dome Field near Casper, Wyoming, located approximately 800 miles away from FEDR. The costs would be substantially higher due to more pipeline transport and the added costs of storage.

The estimated increase in capital costs for the CCS equipment needed for capture and compression would be up to approximately 80 percent[2] for a grass root facility. As stated in subsection 4.2.5.2.1, the costs are expected to be higher at a modified facility due to issues associated with pre-existing piping and infrastructure issues. Pipeline transportation and injection/storage are estimated to be $1.5 - $23 per tonne CO_2 (equivalent to $1.36 to $20.86 per US ton) and are highly dependent on distance to nearest available carbon storage facility, terrain the pipeline must pass through, type of storage reservoir, existing infrastructure, regional factors, etc. In addition, adding the CCS would result in an appreciable energy penalty simply because the CCS process will use energy produced by the plant resulting in a loss of efficiency which may in turn potentially increase the natural gas fuel use of the plant to overcome these efficiency losses.

In this submittal, the costs associated with pipeline transport of CO_2 post-capture are estimated using the March 2010 National Energy Technology Laboratory (NETL) document "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447"[3]. The calculations of estimated costs associated with materials, labor, indirect costs and right of way acquisition were based on functions of pipeline diameters and lengths that were determined as appropriate for the site. Additional costs associated with compression, amine scrubbing, surge protection and pipeline control were taken directly from the NETL document. The nearest CO_2 delivery line to the refinery is a pipeline operated by Anadarko Petroleum, located approximately 90 miles away. Assuming the Anadarko Pipeline could receive effluent from FEDR's amine system and use it to support EOR, the cost per short ton CO_2 removed is estimated at over $382.6 /ton and the total cost is estimated to be over $267 MM. This cost exceeds the capital cost of the new combustion units.

In order for the pipeline to accept scrubbed CO_2 from the new combustion units the effluent stream would have to be further concentrated and pressurized, corresponding to more equipment in addition to the amine unit, cryogenic unit and dehydration unit needed for necessary separation. Unlike a natural gas plant set up to separate and compress CO_2, the refinery does not currently have a system for CO_2 separation. Therefore, additional site-specific energy consumption for CO_2 separation and

---

[2] "Report of the Interagency Task Force on Carbon Capture and Storage", August 2010, pg 33 (http://www.epa.gov/climatechange/policy/ccs_task_force.html)

[3] "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447", The US Department of Energy and National Energy Technology Laboratory, 2010.

compression would need to be taken into considerations for CCS implementation. It is likely that this additional energy consumption will affect the CO_2 efficiency from the new combustion units.

Due to the extraordinary costs of implementing CCS at the refinery, it is considered a technically infeasible and economically unreasonable control option, and is not selected in the 5-step top down BACT analysis. See Table 5-3 at the end of this section for a detailed breakdown of the estimated costs.

These adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CCS. Therefore, CCS does not represent BACT for the new combustion unit associated with this project.

5.2.1.5.2.2 Carbon Transport and Storage

In addition to the adverse economic impacts that show CCS is not a viable option for this project, the use of CCS for new combustion units would entail significant adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of these systems. In order to capture, dry, compress, and transport to a suitable enhanced oil recovery (EOR) site, the CO_2 available for capture from the new combustion unit would require excessive amounts of additional electric power and steam generation capacity. The generation of the steam and electric power required by the project would itself result in GHG emissions, which would offset some if not all of the net GHG reduction achieved by capturing and storing the CO_2 emitted by the new combustion unit.

5.2.1.6 Step 2 – Selection of BACT

The use of CO_2 capture at FEDR would entail significant adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of these systems. In addition to the adverse impacts from steam and electricity generation that will be needed, the capital cost of the equipment to capture, dry, compress, and transport CO_2 make it economically infeasible. The adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CO_2 capture for this project and does not represent BACT for the new combustion unit.

FEDR will incorporate the use of low carbon fuels (refinery fuel gas and/or natural gas), good combustion practices, and energy efficient design where possible for the new combustion unit to meet BACT.

5.2.2 BACT For Fugitive Emissions

Fugitive leaks from new piping and process fugitive components may contain a percentage of CH_4 emissions and, as such, are a source of GHG associated with the project. BACT for the CH_4 emissions from fugitive emissions is evaluated as follows, though at less than 0.05% of the total hydrogen plant's GHG emissions, the total estimated fugitive CH_4 emissions as CO_2e are predicted to have a very negligible contribution to the plant's total GHG emissions.

5.2.2.1 *Step 1 – Identify All Potential Control Technologies*

It is infeasible to capture GHG emissions from fugitive sources. Therefore, CCS is not an add-on control technology that has a potential for application and it is not identified as a feasible technology for controlling fugitives. However, fugitive GHG can be reduced by utilizing a leak detection and repair (LDAR) program.

The potential control practices and technologies for process fugitive emissions of CO2e are based on compliance with the EPA Refinery MACT LDAR program. Although LDAR is currently only required for VOC (and not methane) sources, an acceptable LDAR program will indirectly minimize GHG fugitive emissions. Specifically, the implementation of an LDAR program will:

- Identify and repair any VOC-related leaks will result in a reduction of GHG emissions from these piping components.

- Require use of equipment designs that result in minimal VOC (and thus GHG) fugitive emissions.

5.2.2.2 *Step 2 – Eliminate Technically Infeasible Options*

All of the technologies listed in Step 1 except CCS are technically feasible.

5.2.2.3 *Step 3 – Ranking of Remaining Control Technologies by Control Effectiveness*

FEDR intends to implement all technologies listed in Step 1. The most effective identified control strategy for GHG emissions from equipment leaks is compliance with the EPA for Refinery MACT, which will not result in any adverse energy or environmental impacts.

The components associated with the new combustion units will be subject to the EPA Refinery MACT LDAR program which has specific leak definitions and monitoring requirements. Therefore, an LDAR program complying with Refinery MACT for fugitive components is proposed as BACT and constitutes the most stringent LDAR applicable option.

5.2.2.4 *Step 4 – Economic Evaluation of Ranked Controls*

FEDR intends to implement the EPA's Refinery MACT LDAR program to minimize fugitive GHG emissions via identification and repair of leaks and implementation of compliant equipment design standards. Therefore, an economic evaluation is not required to reject any potential control technologies.

5.2.2.5 *Step 5 – Selection of GHG BACT for Fugitives*

FEDR proposes that implementing the EPA's Refinery MACT LDAR program constitutes BACT for CO_2e emissions from the new combustion units.

Table 5-3
Estimated Cost for CCS of Stack CO_2 Emissions
Frontier El Dorado Refinery

CO_2 Pipeline Data

Pipeline Length	90 miles	to Andarko CO_2 Pipeline
Pipeline Diameter	6 inches	
Number of Injection Wells		
Short Ton of CO_2	115,302.37 tons/yr	
Captured Short Ton of CO_2	107,231 tons/yr	

CCS Cost Breakdown

Cost Type	Units	Cost	
		Pipeline Costs	
Pipeline Materials	$ Diameter (inches), Length (miles)	$64,632 + \$1.85 \times L \times (330.5 \times D^2 + 686.7 \times D + 26,920)$	$ 7,213,842.30
Pipeline Labor	$ Diameter (inches), Length (miles)	$341,627 + \$1.85 \times L \times (343.2 \times D^2 + 2,074 \times D + 170,013)$	$ 32,777,858.30
Pipeline Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + \$1.58 \times L \times (8,417 \times D + 7,234)$	$ 8,360,225.20
Pipeline Right of Way	$ Diameter (inches), Length (miles)	$48,037 + \$1.20 \times L \times (577 \times D + 29,788)$	$ 3,639,037.00
		Other Capital	
Compression	$	14,000,000	$ 14,000,000.00
Amine Unit	$	200,000,000	$ 200,000,000.00
CO_2 Surge Tank	$	1,150,636	$ 1,150,636.00
Pipeline Control System	$	110,632	$ 110,632.00
		O&M	
Fixed O&M	$/mile/year	8,632	$ 8,632
		Total Pipeline Cost =	$ 267,260,862.80

Amortized Cost

Total Capital Investment (TCI) =			$ 267,260,862.80
Capital Recovery Factor (CRF) = $i(1 + i)^n/((1+n)^n - 1)$			0.15
i = interest rate =	0.08		
n = equipment life =	10	years	
		Amortized Installation Costs = CRF*TCI =	$ 39,829,749.73

Total Pipeline Annualized Cost	$ 41,024,642.22
Cost per short ton CO_2	$ 382.58

6.1 GHG Impacts Analysis

An impacts analysis for GHGs is not being provided with this application in accordance with EPA's recommendations:

> "Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not contribute to a violation of the NAAQS are no applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO_2 or GHGs."

6.2 GHG Preconstruction Monitoring

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations:

> "EPA does not consider it necessary for applications to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provision that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs."

6.3 Additional Impacts Analysis

A PSD additional impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> "Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applications or permitting authorities to assess impacts for GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions order of magnitude larger than the emissions for individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would

serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHG."

6.4   Environmental Justice Analysis

The construction and modification associated with this application will be within the refinery. The GHG emissions associated with the project will be from a furnace, and a small amount of CH_4 from potential equipment leaks and cooling tower leaks. FEDR believes that the level of emissions associated with this project should not have any impacts concerning environmental justice.

6.5   Endangered Species

If requested, a Biological Assessment on GHG emissions associated with the NFP will be submitted to the KDHE.

6.6   Essential Fish Habitat Assessment

If requested, a Fish Habitat Assessment on GHG emissions associated with the NFP will be submitted to the KDHE.

6.7   National Historic Preservation

El Dorado contains the following listed National Register of Historic Places or National Historic Landmarks:

- James T. Oldham House
- El Dorado Carnegie Library
- Butler County Courthouse
- El Dorado Missouri Pacific Depot

The construction and modification associated with this application will be within the refinery boundary, which is located greater than one mile away from the nearest National Historic Place. Therefore, the project is not expected to have any impact on a National Historic Place or National Historic Landmark.

This section provides a summary demonstration that the proposed project will meet applicable Federal and State Regulations.

7.1   Federal Regulation Applicability

The following federal standards are potentially applicable to the NFP permit modification including Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) standards.

7.1.1   New Source Performance Standards (NSPS)

NSPS regulations require new, modified, or reconstructed sources to control emissions to the level achievable by the best-demonstrated technology as specified in the applicable provisions. Moreover, any source subject to an NSPS is also subject to the general provision of NSPS Subpart A, unless specifically excluded. 40 CFR Part 60 (NSPS) were reviewed to determine applicability to the proposed project.

7.1.1.1   *NSPS Subpart Ja*

The new HGU-3 furnace will be subject to NSPS Ja since it will be constructed after to the effective date of NSPS Ja.

7.1.1.2   *NSPS Subpart GGGa*

Subpart GGGa is an applicable Standard of Performance for equipment leaks of VOC in Petroleum Refineries for which construction, reconstruction, or modification commenced after November 7, 2006.

The NFP is expected to cause an increase in VOC emissions from equipment leaks with a capital expenditure[4] and will trigger applicability of Subpart GGGa. FEDR will comply with the applicable requirements of this subpart no later than 180 days after startup. This same equipment is also potentially subject to similar provisions under 40 CFR Part 61, Subpart V and 40 CFR Part 63, Subpart CC.

As specified in 40 CFR 63. 640(p)(1), equipment that is subject to Subpart CC but also subject to Part 60 and/or Part 61, shall comply with Subpart CC. However, as specified in 40 CFR 63. 640(p)(2), equipment that is subject to Subpart CC but also subject to NSPS Subpart GGGa, shall comply with NSPS Subpart GGGa. Accordingly, FEDR will modify its current LDAR program to incorporate all affected equipment leak components associated with the project. This will demonstrate

---

[4] Capital expenditure is defined in 40 CFR 63.481a

compliance with the NSPS Subpart GGGa requirements, and applicable requirements under Part 61 that are not exempt under NESHAP Part 63 Subpart CC.

7.1.2 National Emissions Standards for Hazardous Air Pollutants (NESHAPS) Part 61

7.1.2.1 *NESHAP Subpart V*

Fugitive equipment from the affected facilities under the proposed project is potentially subject to NESHAP Part 61 Subpart V. However, as stated previously, equipment that is subject to Subpart CC but also subject to Part 60 and/or Part 61, shall comply with Subpart CC. FEDR will comply with the applicable requirements of this subpart for any requirements that are deemed not exempted from NESHAP Part 63 Subpart CC.

7.1.2.2 *NESHAP Subpart FF (BWON)*

Wastewater containing benzene from the project's affected units is potentially subject to BWON requirements. FEDR will comply with the applicable requirements of this subpart for applicable requirements of this subject.

7.1.3 National Emissions Standards for Hazardous Air Pollutants Part 63

The National Emission Standards for Hazardous Air Pollutants (NESHAPs) listed in 40 CFR Part 63 are source-category specific regulations that limit emissions of HAPs. The NESHAPs are generally only applicable to major sources of HAPs. A HAP major source is defined as having potential emissions in excess of 25 tpy for total HAP and/or 10 tpy for any individual HAP. The facility has potential emissions of individual HAPs greater than 10 tpy and combined HAPs greater than 25 tpy. NESHAPs apply to sources in specifically regulated industrial source categories (Clean Air Act Section 112(d)) or on a case-by-case basis (Section 112(g)) for facilities not regulated as a specific source type. In addition, any source subject to a 40 CFR Part 63 NESHAP is also subject to the general provisions of 40 CFR Part 63 Subpart A, except where expressly noted.

7.1.3.1 *NESHAP Subpart H – Not Applicable*

The equipment leak fugitive emissions associated with new equipment for the project are subject to NESHAP Subpart H (National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks). However, as specified in 40 CFR 63.640(k), (i) & (j), the increase in HAP emissions from the NFP project is below the 10/25 tpy the threshold to make the equipment associated will the NFP subject to Subpart H.

7.1.3.2 *NESHAP Subpart CC*

The process units associated with the NFP is potentially subject to NESHAP Subpart CC. FEDR will comply with the applicable requirements of NESHAP Subpart CC.

In addition, as stated in Section 7.1.1.2, the equipment associated with the NFP will be subject to NSPS Subpart GGGa; therefore, FEDR will comply with the applicable requirements of NSPS Subpart GGGa the fugitive emissions from equipment leak components associated with the NFP.

7.1.3.3 *NESHAP Subpart Q – Not Applicable*

The requirements of Subpart Q applicable to Industrial Process Cooling Towers do not apply to the proposed cooling tower changes. Subpart Q applies to cooling towers that are operated with chromium based water treatment chemicals and which are located at major HAP sources. The proposed cooling tower designed to support the project will not be operated with chromium based water treatment chemicals, therefore, this subpart is not applicable.

7.1.3.4 *NESHAP Subpart DDDDD*

The new HGU-3 furnace is subject to NESHAP Subpart DDDDD. FEDR will comply with applicable requirements of NESHAP Subpart DDDDD.

7.2 Kansas Rules for Air Quality Control

Kansas Department of Health & Environment (KDHE) regulations that are potentially applicable to the project are discussed below.

7.2.1 Compliance with State Emission Limits (KAR 28-19-31)

The combustion sources must demonstrate compliance with applicable provisions of KAR 28-19-31, which regulate emissions for indirect heating equipment.

a) The limits in this paragraph are based on lb/MMBtu for various ranges of heat input. For the HGU-3 furnace, the potential emission rate for particulates is based on the AP-42 factor of 7.6 lb/MMscf, which is converted to approximately 0.007 lb/MMBtu. This emission rate is well below the most stringent allowable rate of 0.12 lb/MMBtu in this paragraph.

b) The limits in this paragraph apply to opacity from indirect heating equipment. The limiting opacity is 20 percent for new equipment, and FEDR will meet this limit through the use of refinery fuel gas, natural gas and/or PSA Off-gas for combustion.

c) This paragraph limits the SO_2 emissions to 3.0 lb/MMBtu. As noted in Section 3.0, the expected SO_2 emission rate from fuel gas combustion sources is 0.026 lb/MMBtu based on the higher heating value of fuel gas. This limit is based on compliance with the NSPS (40 CFR 60 Subpart Ja) for fuel gas combustion. The

potential SO_2 emissions from the HGU-3 furnace are well below the applicable limit.

d) This paragraph limits the NO_x emissions from indirect heating sources. The established limits are 0.3 lb/MMBtu for gas and oil fired units with a heat input of 250 MMBtu/hr or greater. The HGU-3 furnace will have a maximum design capacity of 210 MMBtu/hr; therefore, it will not be subject to this requirement.

In conclusion, the combustion of fuel gas at the HGU-3 furnace will comply with the requirements of KAR 28-19-31.

Other applicability of Kansas Air Regulations to the NFP is summarized in Table 7-1 of this section.

Table 7-1

Kansas Air Regulations
Applicability to the Naphtha Fractionation Project

PARAGRAPH	STANDARD/TITLE	APPLICABILITY
28-19-1 -6	Revoked or Reserved	
28-19-7	Definitions	Applies, but no specific requirements
28-19-8	Reporting	Not directly applicable to this permit application.
28-19-9	Compliance Schedule	Applies. Must be in compliance with limits after authorization is issued.
28-19-10	Circumvention	Applies and requires avoidance of circumvention
28-19-11	Exceptions for breakdowns and maintenance	Applies to the facility during those events, and requires compliance with notifications
28-19-12	Measurement of Emissions	Applies when testing/monitoring is required.
28-19-13	Interference with Enjoyment of Life and Property	Applies to all emissions and operations. No requirements for this application.
28-19-14	Permits required.	Cross-references permits. No specific requirements.
28-19-15	Severability	Applies but no specific requirements.
28-19-16	Non-attainment New Source Review	Not applicable to Butler County.
28-19-17	PSD Permitting	Applies. This application is a PSD permit application for .
28-19-18	Stack heights	Applies. Complies with limited stack heights for dispersion.
28-19-19	Continuous Emissions Monitoring	Not applicable.
28-19-20	PM Emission Limits	Applies to processes, coke handling.

Table 7-1
Kansas Air Regulations
Applicability to the Naphtha Fractionation Project -- (Continued)

PARAGRAPH	STANDARD/TITLE	APPLICABILITY
28-19-21	Additional PM Restrictions	Not applicable.
28-19-22	Revoked	
28-19-23	Hydrocarbon Emissions Sources	Not applicable.
28-19-24	Control of Carbon Monoxide	Applies to catalyst regeneration from HGU-3.
28-19-25	Revoked	
28-19-26	Sulfuric Acid Mist Emissions	Not applicable. Applies only to sulfuric acid production.
28-19-27 -29	Reserved	
28-19-30	General Provisions	Applies to indirect heating equipment.
28-19-31	Emission Limits	Limits apply to PM emissions, opacity, NOx, and SO₂ emissions. Facility complies with applicable limits. See Section 7.2.1.
28-19-32	Exemptions	Applies to indirect heating equipment.
28-19-33 -39	Reserved	
28-19-40 -43	Regulations for Incinerators	Not applicable.
28-19-44 -54	Revoked, amended or reserved.	
28-19-55 -58	Air Pollution Episodes	Applicable when triggered, but not applicable to this application.
28-19-59 -60	Reserved	
28-19-61	Definitions	Applicable but no requirements
28-19-62	Testing Procedures (VOCs)	Applicable for testing vapor pressures, etc. Not affected by this application.
28-19-63	Coatings for Automobiles and Trucks	Not applicable. No affected activities.
28-19-64	Bulk Gasoline Terminals	Not applicable since the refinery is located in an attainment area for all criteria pollutants.
28-19-65	VOC limits for storage tanks. (Fixed Roof)	Not applicable since the refinery is located in an attainment area for all criteria pollutants.
28-19-66	VOC limits for storage tanks. (External Floating Roofs)	Not applicable since the refinery is located in an attainment area for all criteria pollutants.
28-19-67	Vacuum systems at Refineries	Not applicable since the refinery is located in an attainment area for all criteria pollutants.
28-19-68	Leaks from Petroleum Refineries	Not applicable since the refinery is located in an attainment area for all criteria pollutants.
28-19-69	Cutback Asphalt	Not applicable.

PARAGRAPH	STANDARD/TITLE	APPLICABILITY
28-19-70	Leaks from Gasoline Delivery Vessels and Vapor Recovery	Not applicable since the refinery is located in an attainment area for all criteria pollutants.
28-19-71	Printing Operations	Not applicable.
28-19-72	Gasoline Dispensing Facilities	Not applicable since the refinery is located in an attainment area for all criteria pollutants.
28-19-73	Surface Coating Operations	Not applicable. No regulated operations at this facility.
28-19-74	Wool Glass Manufacturing	Not applicable at this facility.
28-19-75	Revoked	
28-19-76	Lithography Printing	Not applicable at this facility.
28-19-77	Chemical Processing for Alcohol and Detergent Facilities	Not applicable. This facility does not conduct those operations.
28-19-78 -79	Revoked	
28-19-80 -82	Power Generation Monitoring	Not applicable. Facility does not conduct those operations.
28-19-200	General Provisions – Definitions	Applicable but no requirements.
28-19-201	General Provisions – Regulated Compounds	Applicable to analysis for non-criteria pollutants. This analysis has been provided in Section 3.0.
28-19-202	Annual Emissions Fee	Applies. Facility complies with this requirement, but is not part of this application.
28-19-203	Reserved	
28-19-204	Permit Issuance – Public Participation	Applicable to this project.
28-19-205 -209	Reserved	
28-19-210	Calculation of Actual Emissions	Applies. Has been used to calculate actual emissions for inventories and for current actual emissions.
28-19-211	Reserved	
28-19-212	Compliance Methods	Applies to required compliance testing. Not part of this application.
28-19-213 -274	Reserved	
28-19-275	Acid Rain Deposition	Not applicable. Applies to Acid Rain (40 CFR 72) sources.
28-19-300 -304	Construction Permits/ Approvals	Application is submitted as required.
28-19-305-324	Reserved	

PARAGRAPH	STANDARD/TITLE	APPLICABILITY
28-19-325	Compressed Air Energy Storage	Not applicable to this facility.
28-19-326-349	Reserved	
28-19-350	PSD of Air Quality	Applies. This application is a PSD application.
28-19-351-399	Reserved	
28-19-400 -404	General Operating Permits	Not applicable to this facility. Does not have a General Operating Permit.
28-19-405-499	Reserved	
28-19-500 -504 and 510 - 518	Operating Permits including Class I Operating Permits.	Applies to the refinery. Facility will incorporate the Project into the Class I Operating permit. Not part of this application.
28-19-540 -546	Class II Operating Permits	Not applicable. Facility will have a Class I Permit.
28-19-561 -564	Class II Operating Permits for Listed Sources	Not applicable. Facility is not a listed source.
28-19-565 -644	Revoked, amended or reserved.	
28-19-645 -647	Open burning permits	Applicable (facility has an open burning permit) but not affected by the proposed project.
28-19-648	Agricultural Open Burning	Not applicable. Facility does not conduct those operations.
28-19-650	Opacity Limits	Applicable. Limits opacity to 20% for new or modified sources.
28-19-651-713	Reserved	
28-19-712	Idle Reduction	Not located in Johnson or Wyandotte counties.
28-19-713	NOx reductions	Not located in Johnson or Wyandotte counties.
28-19-714	Solvent metal cleaning	Not located or sale solvents in Johnson or Wyandotte counties.
28-19-715-716	Reserved	
28-19-717	Bakery Oven VOC emissions in Johnson and Wyandotte County	Not applicable.
28-19-719	Fuel Volatility	Not applicable. Applies only to Johnson and Wyandotte Counties.
28-19-720	NSPS	Applicable. KDHE regulates federal NSPS (40 CFR 60) except for sited paragraphs. See Section 5.1.1.
28-19-721 -727	Existing Municipal Landfills	Not applicable. Facility does not conduct those operations.
28-19-728	Mercury	Not applicable.

Table 7-1
Kansas Air Regulations
Applicability to the Naphtha Fractionation Project – (Continued)

PARAGRAPH	STANDARD/TITLE	APPLICABILITY
28-19-729	Hospital Incinerators	Not applicable. Facility does not conduct those operations.
28-19-728	Mercury	Not applicable.
28-19-735	National Emission Standards for Hazardous Air Pollutants	Not applicable.
28-19-750 -752	Hazardous Air Pollutants – MACT Requirements	FEDR will comply with any applicable MACT requirements associated with the refinery.
28-19-752a	MACT standards for reconstruction of existing sources	Not applicable to this project. Increase in HAP emissions is below 10/25 tpy.
28-19-753	MACT standards for sources for which USEPA fails to meet certain deadlines.	Not applicable to this project.
28-19-800	General Conformity	Not applicable to this facility operations or sources.
28-19-801	Transportation Conformity	Not applicable to this facility operations or sources.

APPENDIX A
APPLICATION FORM

Kansas Department of Health and Environment
Bureau of Air and Radiation
Phone (785) 296-1570   Fax (785) 291-3953

Notification of Construction or Modification
(K.A.R. 28-19-300 Construction permits and approvals; applicability)

Check one: ☒Applying for a **Permit** under K.A.R. 28-19-300(a)   ☐Applying for an **Approval** under K.A.R. 28-19-300(b)*

---

1) Source ID Number: __0150004__

2) Mailing Information:
   Company Name: _Frontier El Dorado Refining LLC_
   Address: _____P.O. Box 1121_
   City, State, Zip: __El Dorado, KS 67042_

RECEIVED
FEB 11 2013
BUREAU OF AIR

3) Source Location:
   Street Address: _____1401 South Douglas Road_
   City, County, State, Zip: ___El Dorado, Butler County, Kansas 67042_
   Section, Township, Range: _Sections 10 and 15, Township 26S Range 5E_
   Latitude & Longitude Coordinates: _37°47' 35" N, 96°52' 30" W_

4) NAICSC/SIC Code (Primary): __324110/2911 Petroleum Refining_

5) Primary Product Produced at the Source: __Refined Petroleum Products_

6) Would this modification require a change in the current operating permit for your facility?   ☒ Yes   ☐ No
   If no, please explain:

7) Is a permit fee being submitted? ☒ Yes ☐ No
   If yes, please include the facility's federal employee identification number (FEIN #) _91-200233_

8) Person to Contact at the Site: _Andrew Beard_____ Phone: (316) 321-8478
   Title: _Environmental Specialist_

9) Person to Contact Concerning Permit: _Andrew Beard_____ Phone: (316) 321-8478
   Title: _Environmental Specialist_

   Email: _Andrew.Beard@HollyFrontier.com_____ Fax: (316) 321-8584

Please read before signing:
Reporting forms provided may not adequately describe some processes. Modify the forms if necessary. Include a written description of the activity being proposed, a description of where the air emissions are generated and exhausted and how they are controlled. A simple diagram showing the proposed activity addressed in this notification which produces air pollutants at the facility (process flow diagrams, plot plan, etc.) with emission points labeled must be submitted with reporting forms. Information that, if made public, would divulge methods or processes entitled to protection as trade secrets may be held confidential. See the reverse side of this page for the procedure to request information be held confidential. A copy of the Kansas Air Quality Statutes and Regulations will be provided upon request.

Name and Title: __Theresa Wheeler, Environmental Manager_

Address: _____1401 Douglas Road, El Dorado, KS 67042_

Signature: _____ Date: 2 /7 /13 Phone: (316) 321-8354

* If you do not know whether to apply for a permit or an approval, follow approval application procedures.

CALCULATING THE <u>CONSTRUCTION PERMIT APPLICATION FEE</u>

[These requirements are found at K.A.R. 28-19-304(b).]

Calculate the construction permit application fee as follows:

Estimated capital cost of the proposed
activity for which the application is made,
including the total cost of equipment and
services to be capitalized.   **Line 1** $101,600,000

Multiply by .05% (.0005)   x   .0005

Total   **Line 2** $ 50,800

**If Line 2 is less than $100, enter $100
on Line 3.**
If Line 2 is greater than $4,000, enter
$4,000 on Line 3.

Otherwise, copy Line 2 to Line 3.
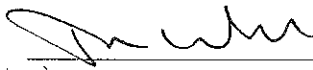
Construction permit application fee.   **Line 3** $ 5,500[*] Minimum fee is $100
Including $1,500 for PSD Review

Theresa Wheeler
(Print)

Certifier of Capital Cost

(Signature)   7 Feb 13   Date

K.A.R. 28-19-350 is a complex regulation pertaining to prevention of significant deterioration (PSD). An additional fee of $1,500 will be required if a PSD review is necessary. If you believe the proposed activity in this Notification of Construction or Modification will be subject to the requirements of K.A.R. 28-19-350, contact the Department for further evaluation.

For purposes of construction permit or approval applications, the following are not considered modifications:
1.   Routine maintenance or parts replacement.
2.   An increase or decrease in operating hours or production rates if:
    a.   production rate increases do not exceed the originally approved design capacity of the stationary source or emissions unit; and
    b.   the increased potential-to-emit resulting from the change in operating hours or production rates do not exceed any emission or operating limitations imposed as a permit condition.

Kansas Department of Health and Environment
Division of Environment
Bureau of Air and Radiation

EQUIPMENT IN VOC SERVICE
(Pumps, Compressors, Pressure Relief Devices, Sampling Connection Systems
Open Ended Valves or Lines, Valves, Flanges, & Other Connectors)

1) Source ID Number: ____0150004____

2) Company/Source Name: __Frontier El Dorado Refining LLC__

3) Normal Operating Schedule: __8760____ hrs/yr

4) Process Unit In Which Equipment Is To Be Located: __Hydrogen Generation Unit No. 3__

5) Design Processing Capacity of the Process Unit: _____20.0 MMscf/day*_____

6) Equipment (Include only that equipment which is in VOC service as defined in 40 CFR Part 60.481. Gas/vapor service, light liquid service, and heavy liquid service are also defined in 40 CFR 60.481):

Equipment Name	Quantity in Gas/Vapor Service	Quantity in Light Liquid Service	Quantity in Heavy Liquid Service
Pumps	0	0	0
Compressors	0	0	0
Pressure Relief Devices **	4	0	0
Sampling Connection Systems	10		
Open Ended Valves or Lines	0	0	0
Valves	98	0	0
Flanges	226		
Other Connectors	0	0	0

7) NSPS Applicability (40 CFR Part 60)

Subpart VV - Standards of Performance for Equipment Leaks of VOC in the Organic Chemicals Manufacturing Industry

Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

Subpart KKK - Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants

-What is the date of construction or modification of the facility ? _____06/01/2013_____

-Does the facility in question have the capacity to produce more than 1,000 Mg/yr?

Yes __X___ ; No _____

EQUIPMENT IN VOC SERVICE
(Pumps, Compressors, Pressure Relief Devices, Sampling Connection Systems Open
Ended Valves or Lines, Valves, Flanges, & Other Connectors)
(cont.)

-Does the facility in question produce heavy liquid chemicals only from heavy liquid feed or raw
materials as defined in 40 CFR 60.481? Yes _____; No __X____

-Does the facility in question produce beverage alcohol? Yes _____; No __X____

-Does the facility in question have any equipment in VOC service? Yes __X____; No _____

*   This capacity is an estimate only and should not be used to be limit facility operation.
         The facility will operate in compliance with the emission limitations of the permit.

**   All relief valves are routed to flares.

Kansas Department of Health and Environment
Division of Environment
Bureau of Air and Radiation

INDIRECT HEATING UNIT (BOILER)

1) Source ID Number: ____0150004_____

2) Company/Source Name: ___Frontier El Dorado Refining LLC_____

3) Emission Unit Identification:___HGU3 - Reformer Furnace_____

4) Manufacturer:_____TBD_____Model No.:____TBD_____

5) Maximum design heat-input rate: ___210 x 10^6_____ BTU/hr (HHV)
    Heat-release Rate: _TBD_ BTU/hr/cu. ft. of furnace volume (HHV)
    Annual load factor: _100 %_
    Heater design: Cyclone _____; Underfeed stoker _____; Spreader stoker _____;
    Pulverized (dry-tangential or normal/wet)_____; Other (specify) _Direct-Fired Catalytic Reformer__
    Normal Operating Schedule: _8760__ hours/year
    Date of latest modification: __6/1/2013_____

6) Primary Fuel Type:
    Natural Gas ____ Oil ____ Coal _____ Other (specify) __Refinery Fuel Gas_____
    Secondary Fuel Type:
    Natural Gas ____ Oil ____ Coal _____ Other (specify) __PSA Off-Gas_____

7) If other fuel is waste liquid:
    What is the source of the waste? ____N/A_____
    Will the waste be pretreated to remove any of the contaminants? Yes ____; No _____ If yes, describe
    method of pretreatment:
    _____
    _____

    If waste liquid is used in combination with fuel oil:
        Specify the volume percent of waste liquid:_____ %
        Specify the anticipated annual operating hours during which the fuel and waste combination will be used:
        _____ hrs.
        Fill in the data below for the fuel oil.
Include the chemical and physical characteristics of the waste liquid. Also, include any source emissions test data
that is available from testing similar facilities that have disposed of this type liquid waste.

INDIRECT HEATING UNIT (BOILER)
(cont.)

8) Fuel Specific Data: (if other is specified, give appropriate data)

Natural Gas:

Heating value: ___1174___ BTU/cu. ft. (avg.) (HHV - Fuel gas) ; 263.4 BTU/cu. ft. (HHV - PSA Off-Gas)

(If fuel gas is used, also specify %Sulfur: ___< 160 ppmv H_2S ___)

Coal:

Fuel Parameters: %Sulfur: _____ % Ash: _____

Heating value: _____ BTU/lb.

Fuel Oil:

Fuel Parameters: %Sulfur: _____ Grade: _____

Heating value: _____ BTU/gal.

Density: _____ lb./gal.

9) Air Emissions Control Technology: NOx _X_ SOx ____ CO ____ Particulate ____

If yes, breakdown of Control Technology:____Ultra Low NOx_____ _____

10) Soot blowing (if applicable): frequency: ___N/A___ duration: _____

11) Has boiler been derated because of: No

Fuel change _____ Equip. limitations _____ Regulatory compliance _____

12) Emissions discharge to atmosphere _TBD_ ft. above grade through stack or duct __TBD__ ft. diameter at _TBD_ °F temperature, with _TBD_ cfm flow rate and _TBD_ fps velocity.

13) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting

14) Did construction, modification, or reconstruction commence after August 17, 1971 and on or before September 18, 1978 and does the indirect heating unit have a maximum design heat-input capacity to combust more than 250 million BTU/hour? Yes _____; No__X___

If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart D.

15) Did construction, modification, or reconstruction commence after September 18, 1978 and does the indirect heating unit have a maximum design heat-input capacity to combust more than 250 million BTU/hour? Yes ___ ___; No__X____

If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart Da.

16) Did construction, modification, or reconstruction commence after June 19, 1984 and does the indirect heating unit have a maximum design heat-input capacity to combust more than 100 million BTU/hour but less than 250 million BTU/hour? Yes __X__ ; No_____

If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart Db.

INDIRECT HEATING UNIT (BOILER)
(cont.)

17) Did construction, modification, or reconstruction commence after June 9, 1989 and does the indirect heating unit have a maximum design heat-input capacity to combust 10 million or more BTU/hour but less than 100 million BTU/hour?   Yes _____ ; No   X___

If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart Dc.

**Kansas Department of Health and Environment
Division of Environment
Bureau of Air and Radiation**

PETROLEUM GENERAL PROCESS

1) Source ID Number: __0150004__

2) Company/Source Name: ___Frontier El Dorado Refining LLC___

3) Type of process (i.e. catalytic cracking, sulfur stripping, etc.): ___Hydrogen Generation___

4) Normal Operating Schedule: __8760__ hrs/yr

5) Operation parameters:

   Process feedstock ___Natural Gas and Hydrogen___

   Rate of process (weight or volume per time) ___20 MMscf/day[*]___

   Supplementary materials (catalysts, additives, etc.) ___Catalyst___

   Rate of input (weight or volume per time) ___15,000 lb/hr___

   End product: feedstock for other processes __Hydrogen__ finished product _____

6) Equipment used in this process which is a potential source of air pollution emissions:

EQUIPMENT	POLLUTANT(S)
HGU3 Reformer Furnace	NO_x, SO_2, CO, VOC, $PM/PM_{10}/PM_{2.5}$, HAPs, GHG
Steam Superheated Coil, Degassifier Vapor Vent, Blowdown Vents	Methanol, Ammonia
FS-HGU3 Fugitives	VOC, CH_4

7) Composition of process emissions: _____

8) Emissions discharged to the atmosphere __TBD__ ft above grade through a stack or duct __TBD__ ft in diameter at __TBD__ °F temperature at __TBD__ ft³/min and __TBD__ ft/sec velocity.

9) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting.

[*] **This capacity is an estimate only and should not be used to be limit facility operation. The facility will operate in compliance with the emission limitations of the permit**

Table B-1
Potential NO$_x$ Emission Calculations for Combustion Units
Frontier El Dorado Refinery

Unit	Equipment No.	Hourly Emission Factor	Units	Annual Emission Factor	Units	Potential Hourly Operation	Units	Potential Annual Operation	Units	Potential Hourly Emissions (lb/hr)	Potential Annual Emissions (TPY)	Baseline Emissions (TPY)	Project Increase (TPY)
Modified/New Units													
HGU3 (New)	HGU3 Reformer Furnace (new)	0.06	lbs/MMBtu	0.04	lbs/MMBtu	210	MMBtu/hr	1,839,600	MMBtu/yr	12.6	36.79	-	36.79
Total Modified/New Units											36.79	-	36.79
Total Increase													36.79
Total Decrease													0
Total Increase and Decrease													36.79

Notes:
1. NOx annual emission factor is based on 40 CFR 60.102a(g)(2)(i)(B), 30 day rolling average. NOx hourly emission factor is assumed to be 50% higher than the 40 CFR 60.102a(g)(2)(i)(B) limit to accommodate any operation fluctuation.

Table B-2
Potential CO Emission Calculations for Combustion Units
Frontier El Dorado Refinery

Unit	Equipment No.	Hourly Emission Factor	Units	Annual Emission Factor	Units	Potential Hourly Operation	Units	Potential Annual Operation	Units	Potential Hourly Emissions (lb/hr)	Potential Annual Emissions (TPY)	Baseline Emissions (TPY)	Project Increase (TPY)
Modified/New Units													
HGU3 (New)	HGU3 Reformer Furnace (new)	0.04	lbs/MMBtu	0.04	lbs/MMBtu	210	MMBtu/hr	1,839,600	MMBtu/yr	8.40	36.79	-	36.79
Total Modified/New Units											36.79	-	36.79
Total Increase													36.79
Total Decrease													0
Total Increase and Decrease													36.79

Notes:
1. CO emission factor is based on vendor guarantee.

Table B-3
Potential SO₂ Emission Calculations for Combustion Units
Frontier El Dorado Refinery

Unit	Equipment No.	Hourly Emission Factor	Units	Annual Emission Factor	Units	Potential Hourly Operation	Units	Potential Annual Operation	Units	Potential Hourly Emissions (lb/hr)	Potential Annual Emissions (TPY)	Baseline Emissions (TPY)	Project Increase (TPY)
Modified/New Units													
HGU3 (New)	HGU3 Reformer Furnace (new)	0.026	lbs/MMBtu	0.0098	lbs/MMBtu	210	MMBtu/hr	1,839,600	MMBtu/yr	5.54	8.98	-	8.98
Total Modified/New Units												-	8.98
Total Increase													8.98
Total Decrease													0
Total Increase and Decrease													8.98

Notes:
SO₂ Emission Factors are based on NSPS Ja limits.

3 Hour H2S Rolling Limit

162 scf H₂S / 10^6 scf / 1020 Btu/scf * 1E6 [Btu/Mmbtu] * [1 lbmol / 385.4 scf * 64 lb SO₂/lbmole] =   0.026 lb SO₂/MMBtu

Annual H2S Rolling Limit

60 scf H₂S / 10^6 scf / 1020 Btu/scf * 1E6 [Btu/Mmbtu] * [1 lbmol / 385.4 scf * 64 lb SO₂/lbmole] =   0.0098 lb SO₂/MMBtu

Table B-4
Potential PM Emission Calculations for Combustion Units
Frontier El Dorado Refinery

Unit	Equipment No.	Emission Factor	Units	Potential Hourly Operation	Units	Potential Annual Operation	Units	Hourly Emissions (lb/hr)	Annual Emissions (TPY)	Baseline Emissions (TPY)	Project Increase (TPY)
Modified/New Units											
HGU3 (New)	HGU3 Reformer Furnace (new)	0.0075	lbs/MMBtu	210	MMBtu/hr	1,839,600	MMBtu/yr	1.56	6.85	-	6.85
Total Modified/New Units										-	6.85
Total Increase											6.85
Total Decrease											0
Total Increase and Decrease											6.85

Notes:
1. AP-42 PM Factor of 7.6 lb/MMscf was converted to lb/MMBtu by divided by 1020 Btu/scf.

Table B-5
Potential VOC Emission Calculations for Combustion Units
Frontier El Dorado Refinery

Unit	Equipment No.	Emission Factor	Units	Potential Hourly Operation	Units	Potential Annual Operation	Units	Potential Hourly Emissions (lb/hr)	Potential Annual Emissions (TPY)	Baseline Emissions (TPY)	Project Increase (TPY)
Modified/New Units											
HGU3 (New)	HGU3 Reformer Furnace (new)	0.0054	lbs/MMBtu	210	MMBtu/hr	1,839,600	MMBtu/yr	1.13	4.96	-	4.96
Total Modified/New Units										-	4.96
Total Increase											4.96
Total Decrease											0
Total Increase and Decrease											4.96

Notes:
1. AP-42 VOC Factor of 5.5 lb/MMscf was converted to lb/MMBtu by divided by 1020 Btu/scf.

Unit		HGU-3	
Source Name		HGU3 Reformer Furnace (new)	Emission Totals
Potential Firing Rate (MMBtu/hr)		210	
Pollutant	Emission Factor[1]	Emissions (lbs/yr)	(TPY)
Organic HAP			
2-Methylnaphthalene	2.4E-05	0.04	0.00
3-Methychloranthrene	1.8E-06	0.00	0.00
7,12-Dimethylbenz(a)anthracene	1.6E-05	0.03	0.00
Acenaphthene	1.8E-06	0.00	0.00
Acenaphthylene	1.8E-06	0.00	0.00
Anthracene	2.4E-06	0.00	0.00
Benz(a)anthracene	1.8E-06	0.00	0.00
Benzene	2.1E-03	3.79	0.00
Benzo(a)pyrene	1.2E-06	0.00	0.00
Benzo(b)fluoranthene	1.8E-06	0.00	0.00
Benzo(g,h,i)perylene	1.2E-06	0.00	0.00
Benzo(k)fluoranthene	1.8E-06	0.00	0.00
Chrysene	1.8E-06	0.00	0.00
Dibenzo(a,h)anthracene	1.2E-06	0.00	0.00
Dichlorobenzene	1.2E-03	2.16	0.00
Fluoranthene	3.0E-06	0.01	0.00
Fluorene	2.8E-06	0.01	0.00
Formaldehyde	7.5E-02	135.26	0.07
Hexane	1.8E+00	3246.35	1.62
Indeo(1,2,3-cd)pyrene	1.8E-06	0.00	0.00
Naphthalene	6.1E-04	1.10	0.00
Phenanthrene	1.7E-05	0.03	0.00
Pyrene	5.0E-06	0.01	0.00
Toluene	3.4E-03	6.13	0.00
Metal HAP			
Arsenic	2.0E-04	0.36	0.00
Barium	4.4E-03	7.94	0.00
Beryllium	1.2E-05	0.02	0.00
Cadmium	1.1E-03	1.98	0.00
Chromium	1.4E-03	2.52	0.00
Cobalt	8.4E-05	0.15	0.00
Copper	8.5E-04	1.53	0.00
Manganese	3.8E-04	0.69	0.00
Mercury	2.6E-04	0.47	0.00
Molybdenum	1.1E-03	1.98	0.00
Nickel	2.1E-03	3.79	0.00
Selenium	2.4E-05	0.04	0.00
Vanadium	2.3E-03	4.15	0.00
Zinc	2.9E-02	52.30	0.03
Total HAP [3]	-	3,472.89	1.74

Fuel Flow (scf/yr)		1,583,779,944.47	
Annual Average Carbon Content (kg C/kg fuel)		0.74	
Annual Average Molecular Weight (kg/kg-mol)		20.56	
Molar Volume Conversion Factor (@ 68° F)		849.50	
HHV (Average of 2010, 2011, Btu/scf)		1,161.53	
HHV (Average of 2010, 2011, mmBtu/scf)		0.0012	
GHG - CO_2	-	229,332,872	114,666
GHG - N_2O (kg/MMBtu)	1.0E-03	4,056.32	2.03
GHG - CH_4 (kg/MMBtu)	1.0E-04	405.63	0.20
Total CO_2e [4]	-		115,299.42

Notes

[1] Emission Factors in units of (lb/10^6 scf); from AP-42 Table 1.4-3 for Organic HAPs, and Table 1.4-4 for Metal HAPs, dated 7/98.

[2] GHG emissions are calculated based on Eq. C-5 for CO2 and Eq. C-8 for CH_4 and N_2O in 40 CFR §98.33

[3] Total Hazardous Air Pollutants (HAPs)

[4] Total Greenhouse Gas Emissions (GHG) in CO_2e

Table B-7

Potential Increase in Emissions from Cooling Tower

Frontier El Dorado Refinery

PM/PM$_{10}$/PM$_{2.5}$ Emissions

Source Description	Tower - Increased Flow Capacity (gpm)	Drift Loss (%)	Drift Loss (gal/hr)	Total Liquid Drift Loss (lb drift/hr)	TDS Content (ppmw)	PM/PM$_{10}$/PM$_{2.5}$ Hourly Emissions[1] (lb/hr)	Operating Schedule (hrs/yr)	PM/PM$_{10}$/PM$_{2.5}$ Annual Emissions (tpy)
Cooling Tower	300	0.020%	3.6	30.0	910	0.027	8,760	0.12

1. PM/PM$_{10}$/PM$_{2.5}$ Hourly Emissions, lbs PM/hr = (TDS Content, ppm) / (1 x 10^6) x (Total Liquid Drift Loss, lbs drift/hr).

2. Drift Loss Rate based on default value in AP-42 Table 13.4-1 of 0.02% for Induced Draft Cooling Towers, Chapter 13.4 of AP-42, 1/95

VOC Emissions

Source Description	Tower - Increased Flow Capacity (gpm)	Fugitive Emission Factor (lb/10^6 gal)	Operating Schedule (hrs/yr)	VOC Emissions (lbs/hr)	Annual VOC Emissions (tpy)	CH$_4$ Emissions[2] (lbs/hr)	Annual CH$_4$ Emissions[2] (tpy)
Cooling Tower	300	0.7	8,760	0.013	0.055	0.003	0.01

1. Emission Factor based on Table 5.1-2, AP-42, 1/95.

2. Assumes that 25% of VOC leaks are CH$_4$

Table B-8

HGU-3: Potential Fugitive Emission Calculations

Frontier El Dorado Refinery

Units	Service	Count	Factor[1] (lb/hr-Source)	Emissions (lb/hr)	Emissions (TPY)
	GV	98	0.00029	0.03	0.12
Valves	LL	0	0.00036	0.00	0.00
	HL	0	0.0005	0.00	0.00
Flanges	All	226	0.00018	0.04	0.18
Pumps	LL	0	0.0041	0.00	0.00
	HL	0	0.0046	0.00	0.00
Compressors	All	0	0.1971	0.00	0.00
Relief Valves[2]	GV	0	0.0986	-	-
Sample Connections	All	10	0.033	0.33	1.45
Drains[3]	All	0	0.00013	0.00	0.00
Average VOC Content	7%				
			Total	0.40	1.75
			Total VOC	0.03	0.12
			GHG[4] - CH$_4$	0.007	0.03
			Total HAP[5]	0.011	0.05

[1] SOCMI Fugitive Emission Factors, excluding factor for drains are from Table 2-5, EPA's protocol for Equipment Leaks Emission

[2] All relief valves in VOC service are routed to the flares.

[3] Drain factor from Table 2-8, EPA's protocol for Equipment Leaks Emission Estimates, for "Other" Equipment Type for Water/Oil

[4] Conservatively assume 25% VOC is CH$_4$

[5] Conservatively assume 40% VOC is HAP

Table B-9

Crude Unit: Potential Increased Fugitive Emission Calculations

Frontier El Dorado Refinery

Units	Service	Count	Factor[1] (lb/hr-Source)	Emission (lb/hr)	Emission (TPY)
Valves	GV	170	0.00029	0.05	0.22
	LL	236	0.00036	0.08	0.37
	HL	133	0.0005	0.07	0.29
Flanges	All	759	0.00018	0.14	0.60
Pumps	LL	7	0.0041	0.03	0.13
	HL	12	0.0046	0.06	0.24
Compressors	All	1	0.1971	0.20	0.86
Relief Valves	GV	9	0.0986	0.89	3.89
Sample Connections	All	7	0.033	0.23	1.01
Drains[2]	All	0	0.00013	0.00	0.00
Average VOC Content[3]	100%				
			Total	1.74	7.61
			Total VOC	1.74	7.61
			GHG[4] - CH$_4$	0.43	1.90
			Total HAP[5]	0.69	3.04

[1] SOCMI Fugitive Emission Factors, excluding factor for drains are from Table 2-5, EPA's protocol for Equipment Leaks Emission Estimates

[2] Drain factor from Table 2-8, EPA's protocol for Equipment Leaks Emission Estimates, for "Other" Equipment Type for Water/Oil Service, < 10,000 ppmv

[3] Conservatively assume 100% VOC

[4] Conservatively assume 25% VOC is CH$_4$

[5] Conservatively assume 40% VOC is HAP

Table B-10
Naphtha Fractionation Tower: Potential Net Increased Fugitive Emission Calculations
Frontier El Dorado Refinery

Units	Service	Count	Factor¹ (lb/hr-Source)	Emissions (lb/hr)	Emissions (TPY)
Valves	GV	15	0.00029	0.00	0.02
	LL	110	0.00036	0.04	0.17
	HL	0	0.0005	0.00	0.00
Flanges	All	392	0.00018	0.07	0.31
Pumps	LL	5	0.0041	0.02	0.09
	HL	0	0.0046	0.00	0.00
Compressors	All	0	0.1971	0.00	0.00
Relief Valves	GV	1	0.0986	0.10	0.43
Sample Connections	All	2	0.033	0.07	0.29
Drains²	All	0	0.00013	0.00	0.00
Average VOC Content³	100%				
			Total	0.30	1.31
			Total VOC	0.30	1.31
			GHG⁴ - CH₄	0.075	0.33
			Total HAP⁵	0.120	0.52

¹ SOCMI Fugitive Emission Factors, excluding factor for drains are from Table 2-5, EPA's protocol for Equipment Leaks Emission Estimates

² Drain factor from Table 2-8, EPA's protocol for Equipment Leaks Emission Estimates, for "Other" Equipment Type for Water/Oil Service, < 10,000 ppmv

³ Conservatively assume 100% VOC

⁴ Conservatively assume 25% VOC is CH_4

⁵ Conservatively assume 40% VOC is HAP

Table B-11
ISOM: Potential Increased Fugitive Emission Calculations
Frontier El Dorado Refinery

Units	Service	Count	Factor[1] (lb/hr-Source)	Emissions (lb/hr)	Emissions (TPY)
Valves	GV	10	0.00029	0.00	0.01
	LL	12	0.00036	0.00	0.02
	HL	0	0.0005	0.00	0.00
Flanges	All	69	0.00018	0.01	0.05
Pumps	LL	1	0.0041	0.00	0.02
	HL	0	0.0046	0.00	0.00
Compressors	All	1	0.1971	0.20	0.86
Relief Valves	GV	1	0.0986	0.10	0.43
Sample Connections	All	0	0.033	0.00	0.00
Drains[2]	All	0	0.00013	0.00	0.00
Average VOC Content [3]	100%				
			Total	0.32	1.40
			Total VOC	0.32	1.40
			GHG[4] - CH4	0.080	0.35
			Total HAP[5]	0.128	0.56

[1] SOCMI Fugitive Emission Factors, excluding factor for drains are from Table 2-5, EPA's protocol for Equipment Leaks Emission Estimates

[2] Drain factor from Table 2-8, EPA's protocol for Equipment Leaks Emission Estimates, for "Other" Equipment Type for Water/Oil Service, < 10,000 ppmv

[3] Conservatively assume 100% VOC

[4] Conservatively assume 25% VOC is CH4

[5] Conservatively assume 40% VOC is HAP

Table B-12
Gas Con: Potential Increased Fugitive Emission Calculations
Frontier El Dorado Refinery

Units	Service	Count	Factor[1] (lb/hr-Source)	Emissions (lb/hr)	Emissions (TPY)
Valves	GV	25	0.00029	0.01	0.03
	LL	95	0.00036	0.03	0.15
	HL	33	0.0005	0.02	0.07
Flanges	All	501	0.00018	0.09	0.39
Pumps	LL	3	0.0041	0.01	0.05
	HL	1	0.0046	0.00	0.02
Compressors	All	0	0.1971	0.00	0.00
Relief Valves	GV	1	0.0986	0.10	0.43
Sample Connections	All	1	0.033	0.03	0.14
Drains[2]	All	0	0.00013	0.00	0.00
Average VOC Content [3]	100%				
			Total	0.30	1.30
			Total VOC	0.30	1.30
			GHG[4] – CH$_4$	0.07	0.32
			Total HAP[5]	0.12	0.52

[1] SOCMI Fugitive Emission Factors, excluding factor for drains are from Table 2-5, EPA's protocol for Equipment Leaks Emission Estimates

[2] Drain factor from Table 2-8, EPA's protocol for Equipment Leaks Emission Estimates, for "Other" Equipment Type for Water/Oil Service, < 10,000 ppmv

[3] Conservatively assume 100% VOC

[4] Conservatively assume 25% VOC is CH$_4$

[5] Conservatively assume 40% VOC is HAP

Table B-13
HGU-3: Potential Atmospheric Vent Emission Calculations
Frontier El Dorado Refinery

Stream	Mass Flow Rate (lb/hr)	Methanol Composition (ppmw)	Ammonia Composition (ppmw)	Methanol Emissions		Ammonia Emissions	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)
Steam Superheat Coil	105,575.43	51	26	9.42	0.11	4.8	0.06
Degasifier	1,417.71	52	27	0.13	0.57	0.07	0.29
Blowdown Drum (Intermittent Blowdown)	20.00	7.3	2.8	0.003	0.0001	0.0001	0.00004
Blowdown Drum (Degasifier down)	717.71	7.3	2.8	0.0092	0.0002	0.0035	0.0001
Total				**9.56**	**0.68**	**4.87**	**0.35**

Notes:
1) The Steam Superheat Coil vents 12/hrs percol startup and there are 2 cold startups/year
2) The Degasifier vent continuously
3) The Blowdown Drum (Intermittent Blowdown) vents for 30 seconds, once per shift, with 2 shifts per day
4) The Blowdown Drum (Degasifier down) vents 2 days per year

Table B-14
HGU3: Potential Fugitive Emissions from Analyzers
Frontier El Dorado Refinery

Standard Volume = 385.40   scf/lb-mole

Analyzer Description	Flow Rate[1]	Units	Pollutant	Molar %[2,3]	Molecular Wt. (lb/lb-mole)	Emission Rates lb/hr[4]	Emission Rates TPY[5]
H$_2$ PSA Feed Analyzer	14	scf/hr	Methane	4%	16	0.02	0.10
			Carbon Monoxide	4%	28	0.04	0.19
			Methanol	0.004%	32	4.6E-05	2.0E-04
			Ethanol	3.00E-05	46	5.0E-05	2.2E-04
H$_2$ Product Analyzer	14	scf/hr	Carbon Monoxide	0.001%	28	9.3E-06	4.1E-05

NOTES

(1) The flow to the analyzers is based on instrument that will be used in the Unit.

(2) The molar percents of methane and carbon monoxide from their respective stream compositions are estimated.

(3) The molar weight percents of methanol and ethanol are based on the composition of a similar feed at a separate facility.

(4) Hourly calculation for H$_2$ PSA Feed Analyzer and H$_2$ Product Analyzer is as follows:

(5) Annual calculation for H$_2$ PSA Feed Analyzer and H$_2$ Product Analyzer is as follows:

(Volumetric Flow (scf/hr)) / (Standard Volume (scf/mole)) * (Molar Weight Percent (%)) * (8760 Hours/year) / (2000 lb/ton)

APPENDIX C
TANKS 4.09D OUTPUTS

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification
User Identification: 65
City: Wichita-Frontier El Dorado
State: Kansas
Company: Frontier El Dorado Refining Company
Type of Tank: External Floating Roof Tank
Description: U. Prem. A

Tank Dimensions
Diameter (ft):   60.00
Volume (gallons):   761,472.00
Turnovers: 79.07

Paint Characteristics
Internal Shell Condition: Light Rust
Shell Color/Shade: White/White
Shell Condition   Good

Roof Characteristics
Type: Double Deck
Fitting Category   Detail

Tank Construction and Rim-Seal System
Construction: Welded
Primary Seal: Mechanical Shoe
Secondary Seal   Rim-mounted

Deck Fitting/Status	Quantity
Automatic Gauge Float Well/Bolted Cover, Gasketed	1

Meterological Data used in Emissions Calculations: Wichita-Frontier El Dorado, Kansas (Avg Atmospheric Pressure = 14.06 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

65 - External Floating Roof Tank
Wichita-Frontier El Dorado, Kansas

| Mixture/Component | Month | Daily Liquid Surf. Temperature (deg F) | | | Liquid Bulk Temp (deg F) | Vapor Pressure (psia) | | | Vapor Mol. Weight | Liquid Mass Fract. | Vapor Mass Fract. | Mol. Weight | Basis for Vapor Pressure Calculations |
		Avg.	Min.	Max.		Avg.	Min.	Max.					
U. Prem. A	All	57.83	52.10	63.56	55.90	5.2455	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

65 - External Floating Roof Tank
Wichita-Frontier El Dorado, Kansas

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
U. Prem. A	2,214.37	210.14	21.47	0.00	2,445.99

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification
User Identification: Tank 253
City: El Dorado
State: Kansas
Company: Frontier El Dorado Refining LLC
Type of Tank: External Floating Roof Tank
Description: Tank 253 Isomerate

Tank Dimensions
Diameter (ft):   110.00
Volume (gallons):   3,163,695.00
Turnovers: 72.82

Paint Characteristics
Internal Shell Condition: Light Rust
Shell Color/Shade: White/White
Shell Condition   Good

Roof Characteristics
Type: Pontoon
Fitting Category   Detail

Tank Construction and Rim-Seal System
Construction: Welded
Primary Seal: Mechanical Shoe
Secondary Seal   Rim-mounted

Deck Fitting/Status	Quantity
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	2
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	17
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	21
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	1
Rim Vent (6-in. Diameter)/Weighted Mech. Actuation, Gask.	1

Meterological Data used in Emissions Calculations: Wichita, Kansas (Avg Atmospheric Pressure = 14.04 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Tank 253 - External Floating Roof Tank
El Dorado, Kansas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F)			Liquid Bulk Temp (deg F)	Vapor Pressure (psia)			Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg.	Min.	Max.		Avg.	Min.	Max.					
Isomerate	All	58.16	52.42	63.90	56.23	5.0034	N/A	N/A	66.0000			76.00	Option 4: RVP=10, ASTM Slope=3

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Tank 253 - External Floating Roof Tank
El Dorado, Kansas

Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
			Losses(lbs)		
Isomerate	4,379.80	395.02	334.71	0.00	5,109.54